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ESTABLISHMENT OF NATIONAL EMISSION STANDARDS FOR STATIONARY SOURCES. VOLUME I. INTRODUCTION, SUMMARY, AND DRAFT REGULATION

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Durham, North Carolina

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ESTABLISHMENT OF NATIONAL EMISSION STANDARDS FOR STATIONARY SOURCES

Volume I Introduction, Summary, and Draft Regulation

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FINAL REPORT

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SECTION 1

INTRODUCTION

This final report gives the results of a six week study the objective of which was to provide a current status report and description information on the most stringent worldwide ordinances, regulations, and best applied technology pertaining to air pollution emissions from the following industries: nitric acid; sulfuric acid; steam-electric power generation, oil, coal, and gas fuel; municipal incinerators; and cement manufacturing. The names and addresses of both domestic and foreign plants utilizing the best technology were to be included. Information sources which were used and available cost data were also required. The pollutants of interest in this study were SO_x, NO_x, particulates, and visible emissions. A draft regulation including suggested methods of analysis was to be provided for the steam-electric power generation industry.

This final report is submitted in six volumes as follows:

Vol. I	Introduction, Summary, and Draft Regulations (This volume)
Vol. II	Steam-electric Power Generation
Vol. III	Municipal Incinerators
Vol. IV	Sulfuric Acid Plants
Vol. V	Nitric Acid Plants
Vol. VI	Portland Cement Manufacturing Plants

Due to the schedule, this report is in draft form with some inconsistences in format among the several volumes and with editorial

corrections inserted. In this form, it is not intended for distribution but only for use as a working document.

This report was prepared by Research Triangle Institute with PEDCo Environmental Specialists, Inc. as a subcontractor. H. L. Hamilton, Jr., served as project supervisor with W. S. Thompson as project engineer. PEDCo contributions were coordinated by George Jutze, president of that organization.

The summary discussions in Section 2.0 through 6.0 are taken directly from the volumes on the five designated industries. They include the identification of the best controlled plants, the applicable regulations and ordinances, and recommendations pertaining to emission standards for new sources. The material in the respective volumes extends this information by providing descriptive information on processes, emissions, and control technology.

Section 7.0 of this report contains a recommended and an alternate draft regulation for the establishment of Federal Standards of Performance for emission control of new sources.

SECTION 2
STEAM ELECTRIC POWER GENERATION *

2.1 Particulate (and Visible) Emissions

As was shown in Table 1, the power generation industry contributed in 1968 about 20% of the total of all particulates emitted in the U.S. In addition to being a major source of particulates, the power industry has been a leader in stimulating the development of and utilizing particulate pollution control systems. In 1966, 86.5% of the particulates generated by the power industry were collected and did not enter the atmosphere (Ref. 1).

2.1.1 Regulation on Particulate Emissions

Regulations which constrain the emission of various air pollutants into the atmosphere must take into account the state-of-the-art in the applicable control technology as well as the cost of control system and the value of the product involved. The control of particulates in the power generating industry is at least as well understood as any other area of air pollution control. Some existing regulations reflect these considerations. For example, in New York City, the regulation on particulates is written in terms of control efficiency rather than in terms of particulate emissions. More specifically, the regulation states that control efficiency must equal or exceed 99%.

The uniform regulation (i.e., one independent of plant capacity) existing in New York City is the only regulation in the U. S. at present which is expressed in terms of collection efficiency. Excluding those in New York City the most stringent regulations in the U. S. at present are shown in Figure 2. Below about 1500 million BTU heat input per hour

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*For reference, see Volume II.

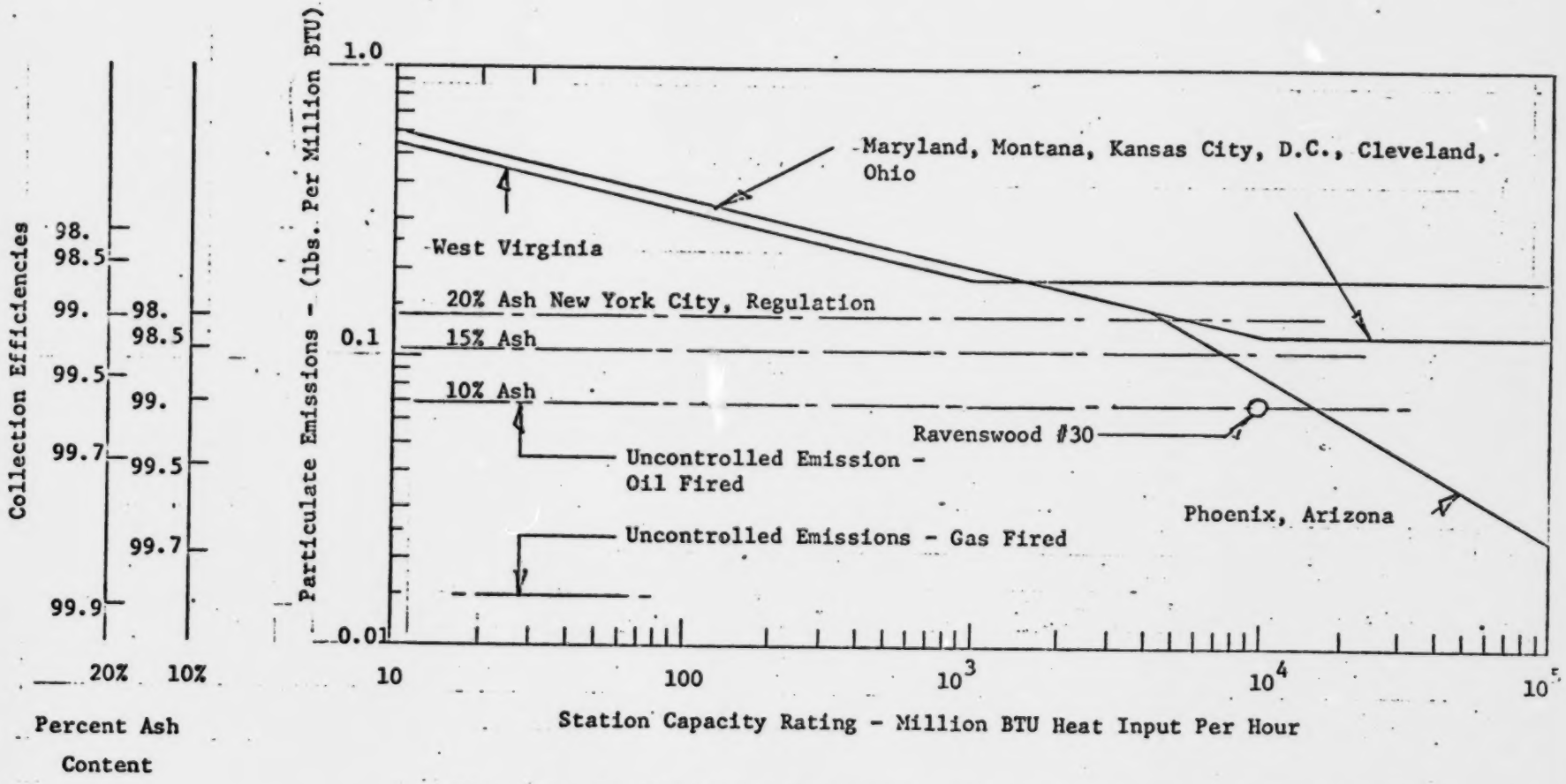

Figure 2. Regulations on Particulate Emissions in Power Generating Industry.

(or approximately 150 MW), regulations existing in West Virginia are the most stringent. Above this capacity rating, regulations existing in Phoenix, Arizona are the most stringent. Note that for capacity ratings above 1500 and below 4000 million BTU heat input per hour, the regulations existing in Maryland; Montana; Kansas City; D.C.; Cleveland, Ohio; and Phoenix, Arizona are identical. With the exception of the Phoenix code, all of the regulations in Figure 2 become uniform for capacity ratings exceeding a specified value. In the case of the Phoenix code for plants exceeding 4000 million BTU heat input capacity ratings, the degree of particulate removal which is required increases at a greater rate than is the case for plants of less than 4000 million BTU input heat capacity ratings.

The two scales on the left in Fig. 2 give the collection efficiencies required to achieve specific levels of particulate emissions from coal-fired boilers. The scales are applicable to coal containing either 10% ash or 20% ash. For example, if a station is burning coal containing 20% ash and its particulate emissions cannot exceed 0.09 lb. per BTU, then the station must be equipped with a particulate collector that is very nearly 99.5% efficient.

Regulations on visible emissions are generally stated in terms of shade and opacity. For example, the Arizona State Department of Health has the following code on the emission of visibles into the atmosphere.

> Reg. 7-1-2.1 SHADE, DENSITY OR OPACITY OF EMISSIONS
>
> No person shall cause, suffer, allow or permit the discharge into the atmosphere from any single source of emission whatsoever any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

1. As dark as, or darker in shade than that designated as No. 2 on the Ringelmann Chart as published by the U.S. Bureau of Mines, or

2. Of an opacity equal to or greater than an air contaminant designated as No. 2 on the Ringelmann Chart.

Another example of emission visible and the most stringent regulation has been proposed by the Maryland State Department of Health and Mental Hygiene with the pertinent sections of the code stated as follows:

_____01 CONTROL AND PROHIBITION OF VISIBLE EMISSIONS FROM INSTALLATIONS

_____0101 Visible Emissions. No person shall cause, suffer, allow or permit the discharge of emissions from any installation or building, other than water in an uncombined form, which are visible to human observers.

2.1.2 Control Technology

There are four basically different systems for the control of particulate air pollutants. These are mechanical collectors, fabric filters, wet scrubbers, and electrostatic precipitators. There are a number of very good articles and reports describing and comparing particulate control systems (e.g., Ref. 1). With respect to the control of particulates in the power generating industry, electrostatic precipitators frequently used with mechanical collectors are the most common type of control system. Mechanical collectors alone are not efficient enough to satisfy existing and proposed particulate regulations. Although fabric filters can achieve the desired collection efficiencies, their poor reliability and uncertain performance have limited their application in the power industry. Considerable research and development has also been directed toward utilizing wet scrubbers. The economic feasibility of using

wet scrubbers for the removal of particulates has not been demonstrated (Ref. 29). However, as described in Section 3.3, some of the wet scrubbers under development for SO_2 removal from flue gases have also shown particulate removal efficiencies greater than 99%. The capability of wet scrubbers, when needed for SO_2 control, may thus preclude the need for a precipitator. Thus, at present the electrostatic precipitator represents the only approach which is both economically feasible and gives collection efficiencies which are required in meeting existing and proposed particulate emission regulations.

Electrostatic precipitators have been used in the power generating industry for over 30 years. Early in this period collection efficiencies were typically 75%. At present, a number of large electrostatic precipitators are being designed with collection efficiencies in excess of 99% and are being installed at power generating stations throughout the U.S. The precipitator installed at Ravenswood Unit 3 of the Consolidated Edison in New York, New York represents the best operating particulate control system in the power industry. The Ravenswood Unit 3 station is a 1000 MW, two-boiler, coal and oil-fired generating system. The station was partly operational on oil in 1967 and fully operational on coal and oil in 1969. The electrostatic precipitator and mechanical collector installed at Unit 3 were manufactured by Research Cotrell, Inc. Brief descriptions of both the mechanical collector and electrostatic precipitator are presented in Ref. 27 and are reproduced in the following table:

Description of Mechanical Collector and Electrostatic Precipitator at Ravenswood Unit 3

Mechanical Collector

Multi-tube, cyclone-type collector consisting of 1264 10-in. diameter Cyclo-trell collecting tubes per precipitator, or a total of 5056 tubes for the entire installation.

Electrostatic Precipitator

Four individual precipitators, each comprised of four units containing eight electrical sections each. Each contains 35 electrostatic ducts. Sixty-four 70-KVP, 750-MA electrical sets consisting of silicon diode rectifiers tanked with transformer.

One hundred and twenty-eight bus sections supplying half-wave rectified voltage to the precipitators.

Saturable core reactors	64
CAS automatic control units	64
Electric plate rappers	320
Electric wire vibrators	120

Collecting area	1,008,000 ft^2
Collecting area per 1,000 CFM of gas	234 ft^2
Bus sections per 100,000 CFM of gas	2.98
Velocity through precipitator	5.67 ft per sec
Treatment time	5.30 sec.

This particular installation is of importance for the following reasons:

(1) The system has been operational for nearly two years and its performance has been evaluated.

(2) The electrostatic precipitator is designed to collect fly ash from low-sulfur coal (<1% sulfur content).

(3) Fly ash from both coal and oil are collected efficiently.

The design performance data and guarantee conditions for mechanical collector and electrostatic precipitator are given in the following tables:

PERFORMANCE DATA

Gas flow, CFM at 700F	4,300,000	3,230,000	2,150,000
Precipitator efficiency,%	99.2%	99.8%	99.9%
Mechanical collector efficiency, %	59%	47%	2%
Guaranteed overall efficiency, %	99%	99%	99%

Draft loss, inches of water

Flues and Electrostatic Precipitators	3.75
Collector	2.50

GUARANTEE CONDITIONS

Gas	4,300,000 CFM at 700F 750 F maximum
Fuels	Coal - Pulverized bituminous Gas - Sweet natural Oil - Residual fuel oils now commercially available in Port of New York and heavier residuals to 1500 S. S. F.
Dust	Inlet loading - 0.5 to 2.5 grains per cu ft of gas at 700 F Combustible - From 0.2 to 25% by weight on dry basis Sulfur - From 0.6 to 3.0% by weight on dry basis

Since the Ravenswood Unit 3 became operational in early 1969, two tests have been performed to determine precisely the particulate collection efficiency. The measured collection efficiencies were 99.6% and 99.2% (Ref. 28). As indicated in the preceding, the electrostatic precipitator was designed to collect fly ash from coal with low sulfur content as required by New York air pollution regulation. Electrostatic precipitators are usually operated down stream from the air heaters in the boiler system;

the gas temperature at this point is approximately 300°F. At this temperature, the electrical resistivity of fly ash increases very rapidly as the sulfur content of the coal is reduced. This increase in resistivity significantly degrades the operation of electrostatic precipitators. At temperatures higher than approximately 500°F and lower than approximately 250°F, the electrical resistivity of fly ash is essentially independent of the sulfur content of coal. Thus, the electrostatic precipitator at Ravenwood Unit 3 has been designed to operate between the boiler and the air heater at a temperature of about 700°F. This high temperature also allows effective collection of ash from both coal and oil.

The cost of the electrostatic precipitator and mechanical collector was approximately 5 million dollars including installation. The cost of fly ash handling equipment (conveyors, storage, and unloading equipment) and steel supporting structures for the entire particulate removal system was in excess of 5 million dollars. Thus, the entire system cost was slightly in excess of 10 million dollars (Ref. 28). Using formulas and approximations in Ref. 1, the annual maintenance and annual operating costs are estimated to be $90,000 and $450,000 respectively. It is stressed that these annual maintenance and operating costs are estimated and have not been verified by Consolidated Edison.

2.2 Sulfur Oxides

In this section the existing standards of states and local areas for SO_2 emission control and the currently available control technology applicable to sulfur oxides are reviewed.

2.2.1 Regulations

Oil-Fired Plants

The most stringent regulations on sulfur emissions presently in effect are those in New Jersey (Chapter X of the State Code), becoming effective on October 1, 1970, which require 0.4% sulfur content* for No. 4 oil and 0.5% for Nos. 5 and 6 oil** or their equivalent of 0.42 (for No. 4) and 0.52 (for Nos. 5 and 6) pounds of SO_2 emitted per million BTU gross heat input. A 0.5% sulfur content requirement has been in effect in Los Angeles County, California, since 1959 and several others since 1969. Even though the western utilities use natural gas, it is not available 100% of the time. Oil is their secondary fuel and they thus have been affected by the regulations.

Effective October 1, 1971, New Jersey regulations will tighten to 0.3% sulfur content for all residual (No. 4 or heavier) fuel oil combustion or the equivalent of 0.3 pounds of SO_2 emitted per one million BTU input. A similar regulation is proposed for New York at the same time (Ref. 25).

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* All percent sulfur contents referred to in this section are on a "by weight" basis.

** There is also a 0.2% sulfur content requirement on No. 2 oil, but to our knowledge utilities do not generally burn this.

Coal-Fired Plants

The most stringent regulations on sulfur emissions presently in effect for coal are those in several California counties (Los Angeles, for example) requiring 0.5% sulfur content of the fuel. However, power utilities are not affected by this, as they primarily burn natural gas and oil. A Boston area regulation requiring 0.55 pounds of sulfur (not SO_2) per million BTU heat input which is equivalent to about 0.7% sulfur content, became effective on October 1, 1970; however, to our knowledge, power utilities in that area all burn oil and therefore are unaffected. It appears that the most stringent present regulations on coal-fired plants that do affect power utilities are 1% sulfur content (or the equivalent), which are in effect in Maryland and Cleveland, Ohio, which are believed to be areas where coal is burned by power utilities (Ref. 26).

On October 1, 1971, a 0.2% fuel sulfur content regulation becomes effective in New Jersey for all new coal-fired plants, but only for existing plants having a rated hourly capacity less than 450 million BTU heat input (approximately 45 mw). Because oil is the chief fuel in New Jersey, this regulation will probably not affect utilities. At that same time, a 0.3% sulfur content regulation becomes effective in New York subject to approval of the proposed code.

Effective October 1, 1972, a 0.3% sulfur content regulation will be in effect in Philadelphia (Ref. 35). Since it is believed that some coal-fired plants are used there by utilities, this appears to the most stringent regulation on coal-fired plants forthcoming that will affect power utilities. Based on data in Ref. 35, it also appears that all other areas where coal-fired

plants are used by utilities will have at most a 1% sulfur content limit for the near future.

Gas-Fired Plants

So far as is known by us, there are no air pollution control regulations designated for sulfur emissions on gas-fired plants. Some of the regulations, the new Boston one effective October 1, 1971, for example, are stated in terms of fossil fuels, which covers coal, oil, and gas; however, the stated control limits are considerably higher than present emissions on commercial gas.

2.2.2. Control Technology

The usual classification of control methods for SO_x control is in terms of (1) using low sulfur fuels, (2) controlling the formation of SO_2 during combustion, and (3) removal of SO_2 in the flue gases. Only the first and third of these categories are considered adequately developed as potentially effective means of controlling SO_x emissions. The potential for control during combustion is well described in Refs. 2 and 21.

2.2.2.1 Use of Low Sulfur Fuel

If an adequate supply of low sulfur fuels were available at reasonable costs, the logical approach to SO_x control would be to switch to the use of low sulfur fuels. Unfortunately, and as is well known (Ref. 2), fossil fuel which is naturally low in sulfur content is less plentiful and costs

more than high sulfur fuel. Fuel desulfurization has not yet developed to the status where it is commercially feasible to supply all of the needed supply of low sulfur fuel.

Estimates of SO_2 control effectiveness and cost for several fuel switching strategies are presented in Table 6. The sulfur contents considered for the various fuels are those which appear to be most prevalent or most frequently cited in the literature. Operating costs given are based solely on added cost of the new fuel and, for the most part, were obtained from Tables 4-13, 4-14, and 4-15 in Ref. 2*. As fuel costs will vary considerably from region to region, costs were computed separately for each region for which corresponding data were available. From these were selected the minimum and maximum costs shown in Table 6. The intermediate value in parentheses represents the average increase in costs.

Gas

As is already well known, switching to natural gas is the most effective control strategy, but only for certain regions where cost of gas is competitive with coal or oil. For these regions where gas is actually less expensive than coal or oil, the "negative" operating costs for fuel switching were not shown, since most utilities in these areas are probably already taking advantage of this. The lower limit of zero costs

*Even though the fuel prices in Ref. 2 are outdated, the differences in the costs of the various grades and types of fuels are considered representative of present values.

TABLE 6

EMISSION CONTROL EFFECTIVENESS AND COSTS IN USE OF LOW SULFUR FUELS FOR SO_2 CONTROL

Control Strategy	Availability	Emission Reduction (in %)	Capital Costs (in $/kw)	Operating[b] Costs (in mills/kwh)	Cost/Ton of SO_2 Eliminated (in $)
3.5% S Coal to Continuous NG	Presently available	99+	1-2[a]	0.2-(3.5)-5.7	8-(136)-220
3.5% S Coal to Interruptable NG	Presently available	99+	1-2[a]	0-(0.5)-2.4	0-20-96
2.5% S Oil to Continuous NG	Presently available	99+	1[a]	0-(2.7)-13.8	0-(148)-750
2.5% S Oil to Interruptable NG	Presently available	99+	1[a]	0-(1.4)-3.3	0-(77)-180
3.5% S Coal to 1% S Oil	Presently available	72	1[a]	1.7-(1.9)-2.2	92-(103)-119
3.5% S Coal to 0.5% S Desulfurized Oil	0-3 yrs.	86	1[a]	1.0-(2.4)-4.3	45-(109)-195
2.5% S Oil to 1% S Oil	Presently available	60	-	0.1-(1.1)-1.2	16-(173)-190
2.5% S Oil to 0.5% S Desulfurized Oil	0-3 yrs.	80	-	1.6	31
3.5% S Coal to 0.5% S Coal	Presently available	85	-	0.4-(1.2)-3.3	19-(57)-157

(continued)

TABLE 6 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR USE OF LOW SULFUR FUELS FOR SO_2 CONTROL

Control Strategy	Availability	Emission Reduction (in %)	Capital Costs (in $/kw)	Operating[b] Costs (in mills/kwh)	Cost/Ton of SO_2 Eliminated (in $)
3.5% S Coal to 1.4% Cleaned Coal	0-3 yrs.	60	-	0.30-(0.34)-0.38	20-(23)-26

[a] Costs listed were obtained from Ref. 2-11. These include only the cost of converting the boiler for burning the new fuel indicated; no estimates were made of fuel storage investment costs for the new fuel.

[b] Operating costs are based solely on added costs of new low sulfur fuel and thus do not include annualized capital costs which would be negligible.

thus represents the situation wherein, in a particular area, the two fuels would cost the same.

The interruptable gas service is less expensive because it can be supplied at times of less-than-peak-gas-load from the supplier. The cost advantage will be lowered when added storage costs are figured in, however, probably not to the extent that it would ever be higher. A combined strategy of using interruptable gas and a standby fuel such as low sulfur oil could be advantageous to some utilities; an example of this is given in Ref. 2.

The limitation of natural gas as a widely used SO_x control measure because of limited production and increasing demands is widely recognized. Ref. 14 even points out that some utilities that have historically burned natural gas are already in severe trouble with respect to obtaining additional natural gas for new power plants. Importation of liquid natural gas is frequently mentioned as a potential solution for SO_x control; however, the supply has not yet developed and costs are likely to be prohibitive in the near future (Ref. 14).

Low Sulfur Oil

Low sulfur oil is also in relatively short supply in the U.S. and will thus be limited in its use as an SO_x control measure to relatively few plants. Several utilities (Commonwealth Edison, Union Electric, Detroit Edison, Consumers Power, and the Cleveland Electric Illuminating) have obtained, or are in the process of requesting, import quotas for low sulfur residual oil (Ref. 14). Desulfurized oil appears to be competitive with natural low sulfur oils on a cost basis; however, desulfurization processes

are not yet developed to the point of insuring an adequate supply. It has been noted (Ref. 15) that the utilities in the New York area plan to rely primarily on low sulfur oil for meeting emission standards.

Low Sulfur Coal

Table 6 indicates that the use of low sulfur coal can be a competitive method of achieving relatively low SO_x emissions. Unfortunately, the availability of natural low sulfur coal is limited. Increased attention is now being given to coal cleaning, traditionally done primarily for removing fly ash and to meet BTU specifications, for purposes of removing sulfur. Sulfur occurs in coal in three forms: pyrite, sulfate, and organic. Only the pyritic portion, varying between 20% and 80% in most coals, can be removed by present processes. Cost estimates given in Table 6 for cleaned coal are based on an estimated premium per ton of $0.80 to $1.00 (Ref. 14). A good description of the status of coal cleaning is given in Ref. 10.

Coal gasification is also frequently mentioned as a possible solution to SO_x control. Much development is necessary if any of these processes are to become commercially feasible in the near future (Ref. 2).

2.2.2.2 Removal of SO_2 in the Flue Gas

Recognizing that reliance on low sulfur fuels is not likely to achieve the degree of SO_x control needed, many industrial firms have undertaken development of SO_2 flue gas removal processes. More than 50 such processes are under various stages of development throughout the world.

The need for investigating processes in other countries was ruled out with the discovery (Refs. 16 and 17) that U.S. developments were further advanced. In particular, it was learned that the German Reinluft process, which has been widely publicized as the most advanced, has experienced too many difficulties to be considered presently suitable for full-scale commercial operation. The Czechoslovakians are reporting far superior SO_2 removal efficiencies for a dry limestone injection than are U.S. developers of the process (Ref. 17); however, no data was available to substantiate this and the Czechoslovakian process was not considered. A number of the foreign processes in development are described in Ref. 18 with most of the foreign developments appearing to center in Germany and Japan.

A number of SO_2 removal processes are in various stages of development in the U.S., but quoting from a recent in-depth study report issued by a distinguished panel of experts (Ref. 8), "... contrary to widely held belief, commerically proven technology for control of sulfur oxides from combustion processes does not exist." This investigation has, in general, confirmed this; however, there are several processes in development which appear to be near-ready for commercial application and for which present cost and performance is adequately known to permit their use as a basis for proposed emission control regulations.

The processes considered are identified in Table 7 along with their availability status, SO_2 removal efficiency, and cost data. All of these are applicable to coal- or oil-fired systems. With regard to availability, it is to be remembered that these processes are not simple off-the-shelf items, but must be designed specially for each power generation

TABLE 7

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital Investment [a] $/KW	Operating Costs [a] mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Limestone injection/wet scrubbing (Combustion Engineering)	1-3 yrs.						
a. 55% load factor (retrofit)		8.3	0.57	N/A	23	N/A	90+
b. 75% load factor (new plant)		6.4	0.43	N/A	20	N/A	90+
Cat-Ox reheat-retrofit (Monsanto)	1-3 yrs.						
a. 55% load factor		36	2.56	2.17	107	91	85
b. 75% load factor		36	2.10	1.71	88	72	85
Dry limestone injection	1-3 yrs.						
a. 55% load factor		11.5 [b]	0.81 [b]	N/A	100	N/A	50
b. 75% load factor		11.5	0.65	N/A	81	N/A	50
MgO scrubbing/(Chemico)	1-3 yrs.						
a. 55% load factor (retrofit)		19	1.25	0.84	50	33	90+
b. 75% load factor (new plant)		20	1.02	0.61	41	24	90+
Potassium Sulfite Scrubbing (Wellman/Lord)	1-3 yrs.						
a. 55% load factor		12.6 (A)	0.96	0.55	37	21	90
		13.5 (S)	1.05	0.79	44	34	85
b. 75% load factor		12.6 (A)	0.80	0.39	31	15	90
		13.5 (S)	0.88	0.62	37	26	85

(A) with acid recovery plant

(S) with sulfur recovery plant

TABLE 7 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital Investment $/KW	Operating Costs mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Cat-Ox integrated new plant (Monsanto)	2-5 yrs.						
a. 55% load factor		32	1.86	1.45	73	57	90
b. 75% load factor		32	1.44	1.03	57	41	90
Electrolysis (Stone and Webster/Ionics)	2-5 yrs.						
a. 55% load factor (retrofit)		17.5	1.26	0.83	46	31	95
b. 75% load factor (new plant)		13.0	0.83	0.40	33	16	95
Lime add-on/scrubbing (Bahco)	2-5 yrs.						
a. 55% load factor (retrofit)		13.8 /c	1.17 /c	N/A	44	N/A	95
Limestone add-on/wet scrubbing (Key West)	2-5 yrs.						
a. 55% load factor (retrofit)		8.9	0.62	N/A	26	N/A	85
b. 75% load factor (new plant)		7.1	0.48	N/A	20	N/A	85

TABLE 7 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital Investment $/KW	Operating Costs mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Sodium carbonate wet scrubbing (Peabody Engineering)	2-5 yrs.	8.3[/d]	1.53[/d]	N/A			70-99+
Sodium carbonate wet scrubbing (UOP Air Correction Div.)	2-5 yrs.	9.6[/e]	0.45[/e]	N/A			85

[/a] With the exception noted cost estimates are based on a 1000 mw plant size, 3.5% sulfur in coal, 18% annualarization rate of capital costs, heating value of coal @ 11,800 BTU/lb., and overall plant efficiency of 34.1%. Variable changes are itemized in detail in Ref. 2-10. When necessary, by-product credit was given on the basis of acid (100%) @ $10/ton and sulfur @ $20/ton.

[/b] Estimates based on 200 mw plant size, and 2% sulfur in coal.

[/c] Estimates based in 200mw existing plant only.

[/d] Data from Ref. 2-19 for cleaning 75% of the flue gas from a 200,000 lb./hr. (approximately equivalent to 20 mw plant) boiler.

[/e] Data from Ref. 2-20 for a 25 mw size plant.

unit or plant. Each of the processes represents a significant investment (from $5.00 to $20.00 per kilowatt capacity depending upon the process) and from initiation of design to the beginning of on-line operation may require from one to several years, representing considerable money and time lost if not successful. None of the processes are developed to the point that the author would, in good faith, recommend for immediate commitment of a utility's funds if they expect to meet the indicated efficiencies on a continuous and reasonably trouble-free operation. The availability indicated for the processes represents when, based on available information, it is considered that a design of the process at a reasonable chance of successful performance could be initiated for a particular installation.

In addition to the processes identified in Table 7, several others that have gained attention in the literature and which appear to belong to the 2 to 5 year availability category are:

Process/Company	SO_2 Removal Efficiency
Molten Carbonate/Atomics International (Ref. 18)	95%
Ammonia Scrubbing/Ovitron (Ref. 18)	98%
Alkalized Alumina/Bureau of Mines (Ref. 18)	85%
Dry Absorbent/Babcock &Wilcox - Esso Research (Ref. 14)	90% (Objective)
Potassium Formate/Consolidated Coal (Ref. 14)	
Limestone Scrubbing/Babcock & Wilcox (Ref. 14)	90% (Objective)
Magnesia Scrubbing/Babcock & Wilcox (Ref. 14)	90% (Objective)
Alkaline Scrubbing/Research-Cotrell (Ref. 14)	

Cost data on these systems was generally too inadequate to report, therefore they were not included in Table 7.

SO_2 flue gas removal systems can generally be classified as either "throwaway", in which the sulfur compound removed is discarded, or as "recovery", in which a (hopefully) salable by-product is obtained from the recovered sulfur compound. These can be distinguished in Table 7 by

whether credit is included in operating costs for recovered sulfur products. (Recovery processes can also be used as throwaway processes if methods of discarding the recovered product are available.) All wet scrubber processes are generally throwaway processes unless the discarded material is salable for landfills, roadbuilding, etc.

The relationship of these processes to the particulates control problem is important. Generally, the use of a wet scrubber process such as the Combustion Engineering or Chemico processes eliminate the need for a precipitator, and the corresponding credit is usually factored into the cost calculations. On the other hand, it is known that the Monsanto process requires a particle removal of 99% efficiency or better (depending on fly ash content) for successful operation of the cat-ox process. The dry limestone injection process requires a very high capacity precipitator as it must remove the normally occurring particulates as well as the calcium sulfate solid particles formed in the boiler for capturing the sulfur.

As adequate descriptions of these processes are given in the literature, detailed descriptions of each of these processes are not given herein. Rather, the remaining discussion is devoted to some pertinent comparisons of the processes and general discussion regarding their applicability to meeting SO_x emission control regulations.

With the exceptions noted, all cost and SO_2 removal efficiency data were taken directly from Ref. 10, which was considered the most reliable source of data available*. With the exception of the dry limestone process, all have

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*Even though other cost data on some processes was reported, the wide difference in process application such as plant size and fuel sulfur content rendered it difficult to compare.

SO_2 removal efficiencies of 85% or greater. Also, the cost data indicates the capital investment will vary widely between about $8 and $36 per kilowatt for retrofitting existing plants and between $6 and $32 per kilowatt for new plants.

Operating costs are also seen in Table 7 to vary widely from about 0.4 to 2 mills per kilowatt-hour. The credit for by-products tends to make the recovery systems competitive with throwaway systems. Projected increases in sulfur product prices (Ref. 22) may possibly tend to favor recovery processes in the very near future.

Costs are sensitive to many factors, one of the main ones of interest being plant size. Generally, the dollars per kilowatt investment cost and the mills per kilowatt-hour operating costs will decrease with increasing plant size. Some good discussion and examples of how costs vary with fuel sulfur content, by-product prices, and plant load factors are given in Ref. 22.

As most utilities will be interested in experiences of others with the various processes, a listing of known applications of the processes in the 1 to 3 year availability category is given in Table 8. Note that several commercial-size (greater than 100 mw.) applications have been made to date, even though their purpose was as prototypes or engineering demonstration models. The 430 mw. application by Combustion Engineering soon to begin operation is the first known full scale, on-line commercial application. This process was sold several years ago at about the time the earlier processes were being installed. Even the manufacturer recognizes that there are further problems to be solved (Ref. 23). A by-pass provision will be included to prevent plant shutdown if difficulties develop. It is also known that Monsanto is actively marketing their cat-ox process; however, to date there are no takers (Ref. 15). The same source also indicated that several others, even

TABLE 8

SO_2 REMOVAL PROCESS APPLICATIONS

Combustion Engineering

Sept. 1968 to present, 140 mw, Meramac Plant, Union Electric Co., St. Louis, Missouri
Nov. 1968 to present, 125 mw, Lawrence Station, Kansas Power and Light Co., Lawrence, Kansas
Early 1971, 430 mw, Lawrence Station, Kansas Power and Light Co., Lawrence, Kansas

Monsanto

Aug. 1967 to July 1969, 15 mw pilot unit, Metropolitan Edison Co., Seward, Pa.
1972, 100 mw, Wood River Plant, Illinois Power, East Alton, Illinois

Tennessee Valley Authority (TVA)

Currently operational, 140 mw, Shawnee Power Plant, TVA, Paducah, Kentucky, (dry limestone proc
Jan. 1972, 150 mw, Shawnee Power Plant, TVA, Paducah, Kentucky, (limestone injection/wet scrubbing)

Chemical Construction (Chemico)

Currently operational, 150 mw, Boston Edison

Wellman/Lord

1967, 1 mw pilot plant, Gannon Station, Tampa Electric Co., Tampa, Florida
1968-1969, 25 mw and prototype, Crane Station, Baltimore Gas and Electric Co.

some of those in the 2 to 5 year availability category, have submitted proposals to utilities for sales.

There has been generally some concern over the availability of limestone (CaO) or dolomite (MgO) for the processes requiring these. Consideration of this (Ref. 24) has confirmed that adequate supplies are available. In fact, if half of all SO_2 removal was done with limestone processes, it is estimated that it would require at most the equivalent of 9% of present U.S. production. As limestone reserves are large with mining operations in 47 states, there should be little difficulty in meeting the demand.

No attempt is made to designate a best process. The suitability of a process will depend on many factors, and what is suitable for one plant may be entirely unsuitable for another.

2.3 Nitrogen Oxides

Regulations on NO_x emissions were investigated with the emphasis on determining the most stringent emission standards. The only NO_x regulations known to us to date are those issued by various California areas. The most stringent standard is an absolute 140 lb. per hour limit on NO_x concentration emitted by any new source currently in effect in several California counties (Los Angeles, San Bernadino, Orange, and Riverside) in the Los Angeles area (Refs. 25 and 33). This is an absurdly low standard for combustion and it is the general consensus that the primary purpose for its enactment was to prevent construction of any new fossil fuel plants.

The next most stringent regulation known for NO_x is the 250 ppm (vol.*) standard in effect in Ventura County, California, and is stated as follows:

Rule 59. Nitrogen Oxide Emissions

> A person in control of a stationary emission source operation shall not permit such operation to emit into the atmosphere gases exceeding in concentration 250 ppm (Vol.) nitrogen oxides (NO_x) calculated as nitrogen dioxide (NO_2) measured at the point of discharge, nor shall the emissions exceed 20 tons per day per source.

This regulation is reasonable as some present proposals for boilers guarantee a 250 ppm level (Ref. 11).

Other known regulations are a 500 ppm standard for Monterey County (Ref. 34) and a proposed 50 ppm standard in New York which will apply only to new plants.

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* For comparative purposes, 250 ppm (vol.) would represent about 700 pounds of NO_x per hour from a 500 mw plant (Ref. 25).

(2) Tangiential firing - which appears to operate at lower temperatures than other designs with reductions of 50 to 60% appearing achievable.

(3) Fluid bed combustion - which offers high heat transfer rates and low temperatures and also which offers the potential advantage of SO_x reduction.

Further development work is required on these techniques before they can be considered generally available as NO_x production methods.

To date, no flue gas treatment methods have been applied to NO_x control of power plants. It has been noted that 20 to 25% reduction of NO_x has been achieved with the limestone type flue gas scrubbing systems under development primarily for SO_x control (Ref. 3) and was confirmed for the Combustion Engineering system (Ref. 36). A good treatment of the status of the development of flue gas treatment methods is given in Ref. 32.

Applications

Most of the applications of NO_x control of boilers has been by Southern California Edison and the Los Angeles Department of Power and Water (LADPW). Tests were initiated in 1959 at the LADPW Scattergood Steam Plant which was emitting over 650 ppm of NO_x at full load for both gas and oil firing. The success with two-stage combustion experimentation prompted LADPW to convert two units to two-stage combustion which resulted in an average NO_x reduction of 27% (Ref. 34). Whereas the later experiences of LADPW in NO_x control were not pursued in depth, the experiences of Southern California Edison cited below are considered to best represent the potential of NO_x control (Ref. 11).

The major source of information on Southern California Edison (SCE) NO_x controls was the contact identified as Ref. 37. SCE uses about 80% gas

and 20% oil. All units are achieving below 250 ppm NO_x emissions except one which represents about 80% efficiency of NO_x reduction from levels before controls were applied. Two stage combustion and air deficiency of 85% of stoichiometric for the first stage are the primary control measures. Six units of Combustion Engineering, Inc., design have been supplied with flue gas recirculation and some of these are achieving 150 ppm of NO_x levels. Operating costs due to NO_x controls are negligible. Similar control measures are also applied when burning oil which is 0.3% sulfur content, exotic Indonesian oil and similar success with NO_x control has been experienced. NO_x emissions with oil-firing have been noted to be more sensitive to air. A tendency has been noted on increased carbon monoxide emissions with NO_x controls; however, no data was available. No information was available on hydrocarbon emissions before and after NO_x control; however, it was noted that controls during oil-firing could produce some increase in hydrocarbons.

SECTION 3
MUNICIPAL INCINERATORS

3.1 Municipal Incinerators Utilizing Best Emission Control Technology

Because the main reason for refuse incineration is volume reduction and sterilization, plants too often have been built and operated without adequate consideration for emission control. The literature shows that the furnace design and operating practices of municipal incinerators are major factors influencing residue quality and burnout, but have lesser effect on effluent material. Mineral particulate emissions, for example, are practically independent of incinerator design; combustible solids and gases emissions are much more influenced by design and operation parameters. Air pollution control systems have a reverse influence on incinerator effluent, having a much stronger effect on mineral particulate than combustibles emissions. Emission of noncombustible gaseous pollutants are a slight function of design and operating practices, but are a strong function of refuse composition. These non-combustibles are affected variably by the air pollution control system used.

A principal consideration in minimizing the emissions of air pollutants from municipal incinerators is employment of appropriate air pollution control systems for the control of mineral particulate. Effective control of combustible pollutant emissions should be directed more toward minimization of pollutant formation and/or maximization of ensuing destruction rates.

The use of air pollution control systems are the most effective in reducing mineral particulate emissions and are the only means of reducing

stack emissions of the non-combustible pollutants. In this study evaluation of effectiveness of existing air pollution control was limited by the lack of available efficiency test data on municipal incinerators. Most tests measure emissions only at the stack. Thus, efficiencies are calculated from theoretical models.

Pollution control for incinerators is essentially particulate control. Substantial technology exists to control this pollutant. A major question arises, however, in the area of particulate emissions. Particulate definition must be related to the testing methods used to obtain emission data.

Two particulate sampling techniques which differ in particulate definition are the American Society of Mechanical Engineers (ASME) Performance Test Codes (PTC 21 and 27) and National Air Pollution Control Administration's (NAPCA) filtration-condensation test procedure. The ASME test determines solid particles filterable by dry filtration methods. The NAPCA "total particulate" includes also the condensable organics and sorbable gases which are trapped at ice-bath temperatures. Mr. Fred R. Rehm, Director, Department of Air Pollution Control, Milwaukee County, Wisconsin raised some interesting questions regarding these two sampling methods at the 1970 National Incineration Conference held by the ASME in Cincinnati, Ohio this past June, 1970. A copy of his open letter addressed to various individuals, government agencies, and professional organizations prior to this conference appears in the appendix of Section C.

Air pollution control systems for municipal incinerators are traditionally selected in an attempt to meet the local emission code. The selections are also reflections of the relative importance of investment versus operating cost trade-offs and of local constraints such as utilities cost, operator qualifications, waste water disposal considerations and aethetics. As a result air pollution control device selections are made on case-by-case basis, considering the requirements of each plant location and the locally established plant performance objectives. For these reasons, maximum available air pollution control technology is seldom, it ever, a consideration in design and construction of present day municipal incinerators.

A purpose of this study, however, included the search for the best utilized air pollution control technology for existing municipal incinerators, both domestic and worldwide. A very complete listing, with general description, of all domestic municipal incinerators is available (A.D. Little Report, Volume 1, Chapter 11-3). From this inventory, a selected group of candidate incinerator facilities were examined more closely in order to determine the effectiveness of the control technology currently in use. (See Table 3-1).

Table 3-2 shows the "best" municipal incinerator from an air pollution viewpoint, tested thus far by the Bureau of Solid Waste Management. The average total particulate is 0.34 grains per standard cubic foot at 12% CO_2. The lowest solid particulate grain loadings are 0.07 to 0.09

Table 3.1. List of Candidate Municipal Incinerators

Location	Built	Tons/ 24 Hr.	Furnace/ Grate	APC Equipment
New Orleans, La. (East)	1967	400	Cont. Reciprocating	Dry Cyclone
Dade County, Fla.	U.C.	900	Reciprocating	Electrostatic Precipitator
Tampa, Florida	1967	900	Rotary Kiln	Peabody Scrubber
Central Wayne County, Michigan	1964	500	Reciprocating	Wetted Baffles
E. 73rd (Brooklyn)	1957	660	Doub. Trav. Grate	Venturi
Southwest (Brooklyn)	1961	1000	Doub. Trav. Grate	Electrostatic
Delaware County, Pa.	1962	500	Doub. Trav. Grate	Wetted Baffles
North Hempstead, N.Y.	1966	600	Rock/Trav. Grate	Scrubber; Cyclor
Issy, Paris	1965	1800	Reciprocating Grate	Electrostatic
Munich - North	1963	1300	Reciprocating Grate	Electrostatic
Montreal, Quebec	U.C.	1200	Reciprocating Grate	Electrostatic
Northwest, Chicago	U.C.	1600	Reciprocating Grate	Electrostatic

U. C. Under Construction

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Table 3.2 Best Utilized Technology

Plant	Location	Air Pollution Control Device	Stack Emissions* Grains/SCF (12% CO_2)	Test Method	Reference
Delaware County #3	Media, Pa.	Wetted Baffles	0.09 0.34	ASME NAPCA	Rehm Test BSWM Test
Central Wayne County	Detroit, Michigan	Wetted Baffles	0.09	ASME	Rehm Test
Hillsborough County #3	Tampa, Florida	Submerged Baffles	0.09	ASME	Environmental Eng. Inc. Test
North Hempstead	Long Island, New York	Water Spray; Cyclone	0.07	ASME	L.S. Wegman Test
E. 73rd St.	Brooklyn, New York	Venturi Scrubber	0.09	ASME	Pilot Test
Southwest	Brooklyn, New York	Electrostatic Precipitator	0.05	ASME	Pilot Test
Issy-Les-Moulineaux	Paris, France	Electrostatic Precipitator	0.03	TUV	Lurgi Report

* Average Values

for medium energy wet scrubbers; 0.09 for the pilot tested venturi and 0.03 to 0.05 for the electrostatic devices. Chemico Corporation indicated verbally that the venturi could achieve 0.05 grains/SCF at a 9" pressure drop and 0.01 at an 30" pressure drop.

In conclusion, it appears that maximum air pollution control of total particulate could be best achieved by using the high energy venturi wet device. If condensables and adsorbable particulate matter can be otherwise minimized, eliminated, or ignored, maximum control for solid particulate would use the electrostatic precipitator.

3.2 Current Emission Regulations for Municipal Incinerators

The principal gaseous emissions from municipal incineration are carbon dioxide, water vapor, nitrogen and oxygen for which no controls are necessary. In recent times, attention has been directed toward the control of sulfur oxides, nitrogen oxides, carbon monoxide, hydrogen chloride and total hydrocarbon emissions from a variety of sources. Except for sulfur oxides, maximum permissable emission levels have not been developed. Criteria does exist in certain critical areas, however, on nitrogen oxides and total hydrocarbons. In the case of solid waste incineration, emissions of all these gaseous contaminants is well below present or contemplated criteria. With the possible exception of the control of those trace emissions that cause odors and, as yet undefined, chemical toxicants, the control of gaseous emissions from municipal incineration is of secondary concern.

Gas suspended particulate matter is the primary concern. Specific quantitative emission limits on gas-suspended particulates are becoming increasingly prevalent in the air pollution codes of many municipalities and States as well as in the operation of Federal facilities. These codes may be expressed in a variety of ways, such as: (1) total weight of suspended particulate per unit volume of exhaust gases; (2) total weight of suspended particulate per unit weight of exhaust gases; (3) total weight of suspended particulate emitted per unit weight of solid waste charged. Further, to prevent compliance with emission codes by simple dilution of stack gases with air to water vapor, almost all codes require correction of these emission limits to a specific reference condition.

At the present time, the most commonly used units for emission values in incinerator practice are pounds suspended solids per thousand pounds of dry flue gas corrected to 50 percent excess air and grains per standard cubic foot (29.92 in. Hg and 70 F) of dry flue gas corrected to 12 percent carbon dioxide. The reference conditions of 12 percent carbon dioxide and 50 percent excess air are approximately equivalent for municipal solid waste.

Some representative gas suspended particulate emission limits have been summarized in the following table.

Emission standards specific for incinerators are relatively new and are undergoing revision. Los Angeles County has for many years

enforced a concentration standard of 0.3 grain per standard dry cubic foot, corrected to 12 percent carbon dioxide, without the contribution of auxiliary fuel. This was a level felt to be attainable with well-designed, multiple-chamber incinerators, without control equipment. In 1966, the Federal Government applied this standard to its incinerators smaller than 200 pounds per hour and required larger units to meet a standard of 0.2 grain per standard dry cubic foot corrected to 12% CO_2. The latter was found to be attainable with installation of certain low-efficiency wet collectors, operating at pressure drops of about 0.5 inch of water. These particular standards have been adopted by many other control agencies in the past few years. The State of New Jersey requires that incinerators with capacities greater than 2000 pounds per hour meet a standard of 0.1 grain per standard dry cubic foot, and smaller ones a standard of 0.2 grain per standard dry cubic foot. (Corrected to 12% CO_2).

In 1967, New York City and New York State developed standards that restrict mass-emission rate in pounds per hour as a function of increasing, incinerator size, as determined by total weight rate of refuse charged in pounds per hour. This is more logical than concentration standards, which are somewhat difficult to standardize for percent of carbon dioxide, if auxiliary fuel is used or if a wet collector is employed. Furthermore, it is more meaningful to restrict mass-emission rate than to restrict effluent concentration.

The standards for Federal Facilities (0.3 and 0.2 grain per standard dry cubic foot, corrected to 12% CO_2) have been converted to equivalent

mass-emission rates on the basis of selected normal refuse. These converted standards, the basis for conversion, and the New York City and New York State regulations are shown in Figure 3-1. The regulations for Federal Facilities represent constant emission concentrations and, hence, require about the same degree of collection efficiency for all incinerators with capacities above and below 200 pounds per hour.

Parallel regulations (e.g., New York State's existing units) also require a single concentration and constant collection efficiency for all sizes. This is less than ideal for reasons already discussed. Larger units discharge more pollutants and are better suited to installation of more efficient collectors.

In addition to provisions limiting the quantities of particulate emission, many codes at the municipal and State level also have opacity restrictions - usually based upon the Ringelmann Chart. The Ringelmann number is determined by a comparative visual observation of the stack plume and a series of reference grids of black lines on white that, when properly positioned, appear as shades of gray to the observer. Although the quality of a plume in equivalent Ringelmann numbers is not easy to determine, trained observers, properly positioned in relation to stack, sun, and wind direction, can provide satisfactorily consistent evaluations. Water vapor plumes complicate observations of stack gases.

The trend in most codes on incinerator emissions based on Ringelmann is to require that: (1) normal continuous plume quality not to exceed Ringelmann No. 1; (2) for short periods not exceeding 3 to 5 minutes in any one hour, plume quality not exceed Ringlemann No. 2, and (3) plume

Figure 3-1.
Typical Particulate Emission Codes for Incinerators Processing Solid Waste

Agency	Emission Limit	Approximate Equivalent Value lb/1000 lb dry flue gas (50% excess air)	g/SCF dry (12% CO_2)
Los Angeles County	0.3 grains per standard dry cubic foot, (12 percent CO_2)	0.48	0.3
U.S. DHEW (Federal Facilities)	0.2 grain/SCF (12% CO_2)	0.36	0.2
Bay Area APCB San Francisco (Reg. 2, Chapter 1)	0.2 grain/std dry cu. ft. (6% O_2)	0.36	0.2
State of New Jersey (Proposed)	0.1 grain/std. dry cu. ft. (12% CO_2)	0.18	0.1
State of Maryland (Proposed)	0.03 grain/SCF (12% CO_2)	0.06	0.03
New York City	0.14 grain/SCF (12% CO_2)	0.27	0.14

quality clearly resulting from water vapor only be excluded from regulation.

Plume opacity refers to the inability of light to pass through the gas plume and is usually applied in cases where the plume is some color other than gray or black. Opacity readings are expressed in terms of percent visibility through the gas plume.

From the standpoint of plant design, a basic problem arises from the fact that the entire technology of particulate collection has been based upon quantitative reduction in the weight of total suspended materials. Thus, to establish the level of control required to meet a given visual code, this code must be expressed in some quantitative gravimetric units. Consistent and general criteria for correlating gas quality measurements, such as Ringelmann number, with quantitative emission in the case of incinerators are not yet available. Therefore, the collection efficiency required to meet a particular Ringelmann number is virtually impossible to predict. Experience with large, coal-fired steam generators indicates that loadings in the range of 0.01 to 0.02 gr. per cu. ft. of exit gas result in stacks optically clear of suspended particulates (i.e., less than Ringelmann No. 1). Achievement of these stack concentrations in coal firing requires collector efficiency in excess of 99 percent by weight. Similarities in particle size distribution from coal-fired steam generators and from incinerators indicate that efficiencies of this order will be required on incinerators if completely clear stack emissions are to be achieved.

3.3 Recommended Emission Levels for New Incinerators

To provide a two-fold basis for recommendation of national standards for particulate emissions from municipal incinerators, both the theoretically achievable levels as well as actual test data were considered:

The theoretical approach involved a calculation of municipal incinerator uncontrolled furnace emissions based on the NAPCA particulate emission factor for refuse incineration and the Kaiser refuse combustion stoichiometry. The theoretical or stoichiometry air for combustion of municipal refuse has been calculated from the ultimate analysis of the refuse on an as-fired basis, as 3.16 pounds of dry air per pound of refuse. This value is equivalent to 42.3 cubic feet of dry air per pound of refuse or 63.5 cubic feet, corrected to 50% excess air.

Uncontrolled furnace emissions can be calculated from this number and the NAPCA emission factor:

$$\frac{17 \text{ lbs particulate/ton (refuse)} \times \frac{7000 \text{ grains}}{\text{pound}}}{\frac{63.5 \text{ SCF}}{\text{lb (refuse)}} \times \frac{2000 \text{ lb}}{\text{ton}}} = \begin{array}{l}0.925 \text{ grain/SCF at} \\ 50\% \text{ excess air} \\ (\sim 12\% \ CO_2)\end{array}$$

At 95% control efficiencies, stack emissions would be 5% or 0.046 grain/SCF (at 12% CO_2); at 99% control, stack emissions would be 1% or 0.009 grain/SCF (at 12% CO_2).

To further substantiate these theoretical values, stack emission data from the best controlled municipal incinerators were further evaluated

to determine the frequency and level of the lowest measured particulate loadings. The Issy, France facility has 6 data values equal to or below 0.01 grains/SCF at 12% CO_2 and 27 additional data values at or below 0.03 grains/SCF at 12% CO_2 (out of a total of 43 data values). The Chemico venturi scrubber pilot test on the East 73rd St. facility had a single measured value (out of 6) of 0.009 grains/SCF at 12% CO_2. This outlet loading of solid particulate was measured at a 9 inch pressure drop, which corresponds to a 95 to 96% collection efficiency. At pressure drops in the 20 to 30 range, collection efficiency can be expected to approach 99%.

The most stringent foreign emission regulation for particulate matter from municipal incinerators is equivalent to 0.079 grains/SCF (dry) at 12% CO_2. The proposed Maryland regulations at 0.03 grains/SCF (dry) at 12% CO_2 is the most stringent domestic regulation. With proper furnace and grate design plus careful operation, the non-solid particulate loading could be substantially reduced from municipal incinerator flue gas. Because the ever-changing nature of the refuse feed fluctuates in moisture content as well as other variables, it is expected that total particulate emissions will always be somewhat higher than the solid particulate loadings. Preliminarily, it would seem proper to consider setting two emission standards on a national basis; one for total particulate, the other for solid or dust loadings. Maximum technology is available in the form of electrostatic precipitator to ensure solid particulate emissions at or below 0.01 grains/SCF (dry) corrected to 12% CO_2. Total particulate

emissions can be kept at or below 0.03 grains/SCF (dry) with the venturi scrubber. It is recommended that the National Emission Standards for particulate matter from municipal incinerators be based on these two figures.

SECTION 4

SULFURIC ACID PLANTS

4.1 Sulfuric Acid Plants Utilizing Best Emission Control Technology

There are two plants in the United States where SO_2 control processes are in operation and are being closely evaluated by the industry. The first is the American Cyanamid plant in Linden, New Jersey, which has the only dual absorption plant presently operating in the United States. The second is the Olin Corporation plant at Paulsboro, New Jersey, where the Wellman-Lord scrubbing process is currently being brought on-stream.

The American Cyanamid plant was designed and constructed by Leonard Monsanto, has a capacity of 700 Tons/Day, uses elemental sulfur for the feed, and produces 93%, 98%, and oleum concentrations of acid. Conversion efficiency is guaranteed to be at least 99.5% and SO_2 emissions to be less than 500 ppm. As of early September 1970, the plant was not continuously operating at full capacity, but on the demonstration run at full capacity, the SO_2 emissions were less than 500 ppm.

Capital cost was approximately 5.5 million dollars, and it was estimated that the cost of the dual absorption over conventional single stage absorption amounted to one million dollars. This figure of one million dollars is an substantial agreement with the comparative costs range presented in the paper by Monsanto on "Interpass Absorption".[1] Using 5.5 million dollars as the cost for the double absorption plant, the cost for a conventional plant would range between 4.7 and 4.9 million

dollars, using the Monsanto figures, or an added cost of between 0.6 and 0.8 million dollars. See Appendix 1 for further cost breakdown.

The Olin plant at Paulsboro, New Jersey, is a 700 Ton/Day regenerative plant handling a variety of spent acids from the South Jersey-Greater Philadelphia area. Average SO_2 inlet to the recovery process is between 5000 and 6000 ppm.

As of late September 1970, the unit was not operating satisfactorily due to problems caused by both the acid plant and the Wellman-Lord process. However, a plant shutdown is scheduled for early October 1970, at which time the problems should be rectified. Wellman-Lord guarantees 90% removal and recovery of the SO_3 and SO_2 respectively and SO_2 stack emissions of less than 500 ppm.

The sulfuric acid plant with the lowest observed SO_2 emissions is the Sudchemie Kehlheim plant in Germany. This relatively small plant (6600 CFM) burns elemental sulfur, has an average conversion efficiency of 99.91% and an average SO_2 outlet concentration of 82 ppm. The inlet SO_2 concentration varies between about 9.0 and 9.3% and the conversion efficiency varies between 99.90 and 99.92.

Table 4.1 summarizes pertinent operating data for some European dual absorption plants. Additional information on the Sudchemie, Kehlheim plant is in Appendix 2 of Section IV.

The Toho Zinc Company at Akita, Japan, uses a dual absorption plant followed by tail gas scrubbing and probably has very low SO_2 emissions. However, emission numbers for this plant are not presently available.

The Division of Air Pollution Control for St. Louis County, reports that the National Lead Plant in St. Louis, Missouri, uses a York Type S mist eliminator and has an average mist emission of 0.65 mg/SCF. This plant is a 400 Ton/Day plant burning elemental sulfur and producing no oleum. This average is based on four tests using the Shell Development method which measures SO_3, H_2SO_4 vapor, and acid mist. The range was 0.6 to 0.7 mg/SCF.

4.2 Specific Regulations Pertaining to Emissions from Sulfuric Acid Plants

Several control districts are either considering or have established a sulfur dioxide emission limit of 500 ppm. The New Jersey State Department of Environmental Protection, Bureau of Air Pollution Control, has stipulated that sulfuric acid plants built after June 15, 1967, must not have sulfur dioxide emissions in excess of 500 ppm. Existing plants must control SO_2 emissions to 2000 ppm.

The St. Louis area has also established a maximum emission level of 500 ppm of SO_2 from new sources as stipulated in the following abstract from the Air Quality Standards and Air Pollution Regulations for the St. Louis Metropolitan Area, March 24, 1967:

> B. Concentration of Sulfur Compounds in Emissions Restricted
>
> 1. No person shall cause or permit the emission into the atmosphere from any existing source specified in subsection A (1) of this regulation, gases containing more than 2000 parts per million by volume of sulfur dioxide from any new source.

TABLE 4.1. OPERATING DATA FOR EUROPEAN DUAL ABSORPTION PLANTS

Plant	SO_2 Source	Gas Flow (SCFM)	SO_2 Inlet Concentration Range %	Conversion Efficiency Range %	Outlet SO_2 Concentration Range ppm
1. Farbenfabriken BAYER Leverkusen Werke Plant #1	Roasting Sulfide Ore	28,600	8.2 - 9.3	99.71 to 99.83	139 to 260
Plant #2	Elemental Sulfur	27,100	8.5 - 9.2	99.78 to 99.83	148 to 202
2. Farbenfabriken BAYER Dormagen Werke	Roasting of Sulfide Ores	(490 Ton/ Day Plant	9.0 - 9.7 (Avg. 9.4)	99.27 to 99.5	510 to 790
3. Berzelius Metallhutten Homburg Zinkhutte	Roasting of Zinc Ore	15,000	5.9 - 6.4	99.60 to 99.73	190 to 300
4. Sudchemie, Kehlheim	Elemental Sulfur	6,600	9.09 - 9.73	99.90 to 99.92	74 to 91
5. Saurefabrik Schweizerhalle Basel, Switzerland	Elemental Sulfur	-	9.9 to 10.5	99.48 to 99.81	220 to 600

> 2. No person shall cause or permit the emission into the atmosphere from any source specified in subsection A (1) of this regulation, gases containing more than 70 milligrams per cubic meter of sulfuric acid or sulfur trioxide or any combination thereof or 35 milligrams per cubic meter of sulfuric acid, sulfur trioxide or any combination thereof from any new source (expressed as sulfuric acid).

The City of Chicago has the most stringent SO_2 and acid mist emission standards. SO_2 emissions are limited to 500 ppm from both new and existing sources as stipulated in the following abstract from Chapter 17 of the Municipal Code of Chicago, Environmental Control Ordinance.

> (4) Sulfur Oxides.
>
> No person shall cause or permit the emission into the atmosphere from any new or existing source gases containing more than 500 parts per million by volume of sulfur dioxide nor more than 15 milligrams per cubic meter of sulfuric acid or sulfur trioxide, or any combination thereof; provided, however, that the foregoing limitations shall not apply to those emissions in which both fuel is burned primarily to produce heat, and the sulfur compound emission is due primarily to the sulfur in the fuel burned.

4.3 Recommended Emission Standards for New Plants

It is entirely possible, as demonstrated by the European plants, to restrict SO_2 emissions to approximately 100 ppm. However, it is not known how long these plants have been operating nor whether these low emission levels can be maintained over a period of several years. Furthermore, because of different economic factors such as the market

and price for sulfur and sulfuric acid, the cost for achieving these low SO_2 emission levels may not be justifiable in the United States.

From a consideration of the different processes available for SO_2 control and the associated cost for this control, an SO_2 emissions standard for sulfuric acid plants between 300 and 400 ppm certainly appears to be feasible.

Acid mist emissions are easier to control when no oleum is being produced and when elemental sulfur is the feed stock. However, it is feasible for all sulfuric acid plants to control acid mist emissions including SO_3 and H_2SO_4 vapor to between 1.0 and 2.0 mg, expressed as 100% H_2SO_4, per standard cubic foot.

SECTION 5
NITRIC ACID PLANTS

5.1 Plants Currently Using Best Technology

While catalytic combustion devices have been used for about 15 years, very few plants have successfully achieved reductions of more than 80% for extended periods of time.

Nitric acid plants currently operating with very low reported emissions levels include:

Plant	Fuel Used	Approximate NO_x Emission Levels, ppm
DuPont, Repauno Plant Gibbstown, New Jersey	Natural Gas	300 - 500 ppm
Shell Chemical Co. St. Helen's, Oregon	Ammonia Plant Purge Gas	100
Cresco Fertilizer Co. Western Port, Australia	Purge Gas	100

5.2 Current Regulations Limiting NO_x Emissions from Nitric Acid Plants

The only regulations currently applied to nitric acid plants utilize the best feasible technology approach, equivalent opacity, and equivalent ambient air NO_x concentration at the plant property line. No regulations in the United States currently specify a quantitative emission value.

Equivalent opacity regulations while not strictly enforced, usually limit the emissions to 20 to 30% opacity.

Best feasible control technology is subject to varied interpretations depending on the type and age of the plant and its specific operating conditions. In West Germany an emission value of approximately 0.437 grains per $ft.^3$ (approximately 360 ppm) of total NO_x is indicative of good control practice. New Jersey's application of best control technology regulation is currently in the 300 - 500 ppm range.

The National Air Pollution Control Administration's Federal Facilities Division has set a maximum hourly property line ambient air NO_x concentration of 0.1 ppm for Federal Operations. This value would apply to all operations at any one site; not just nitric acid plants.

5.3 Recommended Emission Levels for New Plants

The catalytic control techniques presently being applied to nitric acid plant tail gases are undergoing continual improvement and modification. Theoretically, with a sufficient supply of fresh catalyst, and enough excess fuel, a limit of zero NO_x can be approached. However, practicalities of design, economics, and fuel availability currently require a higher emission limitation for continued operation.

Based on the current level of technology the following emission limitations appear feasible for <u>new</u> plants:

1) For plants able to use hydrogen or ammonia plant purge gas as a reducing fuel.

Total NO_x ($NO + NO_2$)	100 to 200 ppm	
NO_2	less than	10 ppm

Equivalent opacity = 0.

2) For plants using natural gas, propane, or similar hydrocarbon fuel.

Total (NO_x + NO_2)	300 to 400 ppm
NO_2	50 ppm

Equivalent opacity = 0.

Due to the changes taking place in emission control technology, these standards should be re-evaluated bi-annually.

SECTION 6

PORTLAND CEMENT MANUFACTURING PLANTS*

6.1 Description of Plant Utilizing Best Technology

Mr. Bruce Kester of Missouri Portland Cement Company is recognized by all of the cement plant officials and the Portland Cement Association executives as one of the most knowledgeable men in the world on the subject of air pollution control in the cement industry. He indicated that he had visited most of the cement plants in this country, in Mexico, and in Canada, and had visited plants in Europe and Asia Minor. Without hesitation, when asked which plant in the world was the best controlled from an air pollution viewpoint, Mr. Kester stated that the Ideal Cement Plant in Seattle, Washington, has the best overall dust control. Dr. Huntzicker and Mr. LeGore of the Portland Cement Association agreed with this statement and so have other industry representatives that are familiar with this plant.

The following description of the Ideal Cement Company Plant in Seattle was obtained from discussions with Mr. J. L. Gilliland, Technical Director of Ideal Cement Company who is located in their office in Denver, Colorado,[15] from an Ideal Cement Company Brochure on the formal dedication of the Seattle Plant on August 23, 1967,[10] and from a paper that describes the plant in detail.[22] A general description followed by a more detailed description dust handling equipment will be given.

The Ideal Cement Plant in Seattle is a 2 1/2 million barrel wet-process system. The compactness of the plant which was made necessary by the 25-acre site turned out to be an advantage in control, operation, accessibility, maintenance and first cost.

*For references see Volume VI.

The plant is fully automated, i.e. operated with complete computer control for all operations except unloading; load-out, and packhouse operations. A direct digital computer controls raw material blending and grinding, kiln burning and cooling, and finish grinding. An x-ray analyzer in the control room provides instant analysis of all materials in the raw material and clinker which gives better quality control and a better product. This computer control has surpassed all expectations of the company's technicians in the approximately three years the plant has been in operation.

Problems involved in design and construction of the plant included unstable soil common to the waterfront area and designing for earthquake resistance. More than 2,900 prestressed, precast 14" octagonal pilings from 50' to 160' in length -- about 55 miles in total length -- with a load-bearing capacity of 150 tons each-support major equipment and structures on heavy foundations. About 4,000 tons of sheet steel piling and more than 120,000 cu. yd. of concrete were used in the plant construction.

Cleanliness of the plant was factor in selecting the precast wall panels and roof slabs. Other efforts for cleanliness included installation of 54 dust collectors -- at every conceivable dust point, 3 complete vacuuming systems, troughs and drag-chain conveyors under belt conveyors to collect spillage, etc.

Pre-crushed limestone, sand, clay and slag are delivered to the plant by barge while gypsum comes by rail. By receiving these raw materials from other locations, one source of air pollution is inherently avoided

at this plant, that of quarrying and initial crushing. The limestone is received at the dock in less than 1 1/2" size.

All raw materials are unloaded by a traveling crane with a 7 cu. yd. clamshell bucket. Unloaded onto a conveyor belt the raw materials are carried to storage areas. From the storage area different types of conveyor systems are used to discharge the various materials in the proportions required for blending.

6.1.1 Raw-Feed Blending

Initial grinding is done in this plant by a single ball mill in closed circuit with screens. Silica sand is pre-ground in a smaller mill to assure proper blending with other raw materials except when Type I cement is being made when it goes directly to the raw mill. The silica and mill is a 6'7" x 14' grate discharge ball mill that is loaded with 25 tons of 2" and 1 1/4" steel balls. It grinds 25 tph to a fineness of 60% through 200 mesh.

The other raw materials generally go directly to the raw mill which is a 2-compartment 11' x 36' F. L. Smidth wet-grinding raw mill. This mill is loaded with 135 tons of CFJI steel balls, with 3" and some 4" in the first compartment, and 2" and 1 1/4" in the second. The mill operates in closed circuit with three 18" Dorr-Oliver DSM screens with 0.6 mm openings. The output averages 640 bbl. per hr. with 99% passing a 50-mesh screen, and 85% passing 200 mesh.

The finished slurry goes to three 50-ft. dia., 8,000 bbl covered concrete kiln feed tanks. These tanks hold enough slurry for 72 hours of

kiln operation. Normally one tank is being filled while another is mixing and the third is supplying kiln feed.

6.1.2 Kiln and Cooler Control

The 15'6" x 14' x 500' Allis-Chalmers kiln is rated at 7,200 bbl. per day capacity. Exit gases are drawn at about 600°F into a Buell SF Model 23 GA electrostatic precipitator, which is rated at 400,000 cfm at 700°F. This precipitator consists of two parallel sections, each with three compartments. The draft fan, a 400,000 cfm Sturtevant unit driven by a 600-hp motor, is preceded by automatic dampers and exhausts 99.4% dust free gases through a 250' Kellogg reinforced concrete stack. An automatic safety cutoff for the precipitator eliminates any possibility of explosions.

Dust is collected in six hoppers under the precipitator and is removed by six pneumatic systems to a pair of 11,000 cu. ft. dust bins, or to waste. One bin usually gets the dust from the first two precipitator compartments which is weighed out and returned to the kiln for insufflation at up to 21 tph. The higher alkali dust from the second pair, about 10% of the total dust, can be leached in a pair of dual rake classifiers. The leached classifier product is pumped to the kiln feed pipe at any desired rate. The overflow from the classifiers is neutralized to a required pH, and cleared, before being pumped to the sewage system. The dust from the last precipitator compartments is sometimes trucked to waste, using a dustless loader with sprays.

The clinker is discharged from the kiln to a 2-section, horizontal-grate air-quenching clinker cooler. This cooler has two grate sections

with a 30" x 126" reversible clinker breaker. Discharge is by two 12" drag chains. Clinker temperature at discharge is 100-110°F.

6.1.3 Clinker Handling and Storage

The clinker is discharged from the cooler to a 24" drag-chain conveyor which, in turn, discharges to a pair of 24" transverse drag chains which are the first units in a dual handling system between the kiln and the mills, to insure against any breakdowns. Clinkers are usually discharged by conveyor to the mill feed bins for final grinding.

6.1.4 Finish Grinding

Clinker which is stored in 28,000 cu. ft. silos is discharged by conveyors. Gypsum from 27,000 cu. ft. silos is added to the mill feed belt. Dry additives are added by feeders, and liquid additives are added by built-in feeders.

The two 12' x 32' finish grinding mills are loaded with 175 tons of CFJI 3", 2", and 1 1/4" steel balls. Each mill operates in closed circuit with an 18' Raymond centrifugal, double-whizzer separator, which receives the mill output by a conveyor. The separator rejects are returned to the mill by another air conveyor. Grinding is done to a fineness of 90% through 325 mesh--105,625 openings to the square inch.

The finished cement goes to vertical cement coolers and from there to storage.

6.1.5 Storage-Packing-Loading

The cement storage facilities consists of 26 silos and 2 interstices with an unusually large total capacity of 373,000 bbl of cement which is

well located for efficient loading out and delivery of bulk or bagged cement by truck, rail or water.

6.1.6 Dust Collection, Miscellaneous

The plant has 53 dust collectors and a kiln precipitator, installed at a cost of more than $4 million and located at every conceivable dust source which is evident in the cleanliness of the plant and its surroundings. (The total plant investment was approximately $30 million.) Thirty-seven of the dust collectors are Pulverizing Machinery-Slick Industrial Co. Mikro-Pulsaire collectors that are fully automatic and self-cleaning. Periodic cleaning of the filter cylinders is accomplished by a momentary jet of high-pressure air at each cylinder.

Two of the 53 collectors are said to be the first bag collectors ever used for venting the second stage of a clinker cooler. (Recently the Kaiser Cement and Gypsum's Permanente, California plant, the West's largest, installed a $1.1 million baghouse system on clinker coolers and is believed to be the first to utilize baghouses connected by a manifold duct system to several coolers. This system was designed with a collection efficiency in excess of 99.9% which virtually eliminates all particulate emissions from clinker cooler exhaust air).[23] The Seattle clinker cooler bags use DuPont Nomex nylon fabric, which is a 16-ounce felt making possible a 7.8 to 1 air-to-cloth ratio. This cloth is continually exposed to temperatures of 275°F, with surges to 375°F, and is expected to last over 30 months. A damper diverts to the stack if temperature exceeds 475°F. A common 125,000-cfm fan is connected to these two collectors.

Other Mikro-Pulsaire bag collectors that range from 2,070 to 36,000 cfm are installed at the gypsum and raw material unloading and handling systems, the raw and clinker silo feeds, the clinker conveyor system, finish mill department, sepatator exhaust (four 36,000 cfm units), cement storage silos, bulk loading stations, and the new packhouse. Dust collectors also clean the air going into the eight electrical rooms and to the compressor room.

For cleanup, there are three Lamson stationary vacuum cleaning systems--in the mill building, in the cooler building and the laboratory area of the main building, and in the new packhouse. There are also two power vacuum sweepers, which keep driveways and other areas clean.

Belt conveyors, with 35° idlers, are used whenever possible and have driffle drag cleanup and hopper bottoms for feed to the dust collectors.

6.2 Air Pollution Control Regulations for Emissions From Cement Plants

About 20 years ago, the Los Angeles County Air Pollution Control District (LACAPCD) developed the process-weight regulation which limited total particulate emission rates from industrial processes as a function of the process-weight rate.[14] Process weight is generally the total weight of all raw materials, including solid fuel but not gases, which are introduced into a process. This method removed dilution as a factor in meeting emission standards.

The Los Angeles regulation was derived after studying the many metallurgical processes located there. The basis for degree of control was determined by analyzing well-controlled and well-operated plants. This regulation demonstrated that many types of industries regardless of the type, can meet the regulation. However, no cement plants are located in Los Angeles County and would have real trouble meeting this regulation. The maximum-allowable emission limit for particulates was set at 40 pounds per hour regardless of the process weight.

In 1959, the Bay Area Air Pollution Control District in San Francisco (BAAPCD) developed another process-weight regulation based on well-controlled industries there.[14] This included some mineral-based processes not found in Los Angeles County. Thus, the Bay Area Regulation is similar to the Los Angeles Regulation in the lower range allowing 12 lbs/hr of emission for 10,000 lbs/hr process weight as compared to 10.0 lbs/hr in Los Angeles, 25.2 lbs/hr as compared to 22.22 lbs/hr for 30,000 lbs hr is identical at 40.0 lbs/hr for 60,000 lbs/hr but increases to a maximum of 92.7 lbs/hr for a process weight of 6 million pounds per hour. This appears to be a more reasonable regulation for a wider range of sources and, therefore, has been

more widely accepted. Although other agencies have developed process-weight regulations, the Los Angeles and Bay Area regulations are the only ones widely accepted. In fact, many states have their own regulations, but they are usually based on one of these two regulations.

The cement industry has trouble meeting even the Bay Area regulation in large plants because relatively difficult technical problems with resulting economic hardship. For instance, in the Ideal Cement Company Plant in Seattle which is considered by all cement plant officials and experts as the best controlled cement plant overall from an air pollution viewpoint invested $4,000,000 in air pollution control equipment out of a total plant investment of approximately $30,000,000.[15]

The State of Pennsylvania has developed a regulation with varying emission limits based on the pollution potential of the source. This regulation has several sets of emission limits which are applicable to different parts of the state. It is designed to require greater collection efficiency for those operations that would discharge large quantities of pollutants. Although the cement industry contributes large amounts of particulates, the Pennsylvania regulation is much less stringent for this type of operation than even the Bay Area regulation. For example, for a large cement plant with a production rate of 9,580 bbl/day, the Bay Area regulation limits the emission rate to 54.6 lbs/hr while the Pennsylvania regulation allows 183 lbs/hr[14]. Similarly for a 3,900 bbl/day cement plant, the Bay Area regulation specifies 45.6 lbs/day and the Pennsylvania one 62 lbs/day.

Most cement plant officials feel that the Los Angeles regulation that stops at 40 lbs/hr emission regardless of the plant size is not realistic for cement plants. Several expressed the opinion that the technology is

not available at this time to meet this regulation.[16] However, one plant official stated that the technology does exist, but it would be very, very costly to meet this regulation.[12] In fact, he further stated that if a system were designed to meet the 40 lbs/hr emission rate and really met it, the pollution control system would be larger and more costly then the entire cement plant itself. Thus, in his opinion it is not practical. He stated that there is a cement plant in Dade County, Florida (which has regulations based on the LA regulation) that is limited to 40 lbs/hr, but definitely does not meet it. However, he further stated that if any plant was designed to meet an air pollution regulation within the last 4 years, it is probably meeting it.

Mr. Charles Bush, Technical Director of Riverside Cement, in Riverside, California, stated that Riverside County has the same air pollution regulations as Los Angeles County[17]. When questioned as to whether his plant was meeting this regulation he stated that it was. On further questioning, he stated that he felt this regulation was being met most of the time but could not guarantee that it was being met continuously. His control equipment included a 16 compartment glass baghouse with an efficiency above 99.5% for a dry process and an electrostatic precipitator with an efficiency of 99.5% to 99.9% for a wet-process kiln.

All of the cement plant officials and two executives from the Portland Cement Association, Dr. Harry Huntzicker, President and Mr. Ivon LeGore, Safety Director, agree that the most stringent air pollution regulation imposed on cement plants in this country is the Los Angeles County Air Pollution Code or those codes patterned after it. Although there are two basic sections in the Los Angeles Code that affect cement plants; i.e., process-weight basis and gas volume concentration, the most stringent

regulation is the one based on process weight. Mr. Jack Gilliland, Technical Director of Ideal Cement Company, stated that the new regulation in the State of Maryland may be even more stringent than the Los Angeles County Code because it specifies no visible emissions at all.

Since the Los Angeles County Code or other codes based on it are the most stringent regulation for cement plant emissions the section of this Code that applies to particulate emissions, including the process-weight table are included herein.* Also, since the San Francisco Bay Area Air Pollution Control District Regulations are the most widely accepted and appear to be more realistic for the Portland Cement Industry, the section of this regulation that applies to particulate emissions is included.

Regulation IV of the St. Louis County Air Pollution Control Code which applies to particulate emissions from industrial processes and is based on the San Francisco Bay Area Code is also included herein to indicate what modifications are typically made when a code is based on another code. It should be noted that the process weight tables and gas concentration tables are identical for the two codes. The Ambient Air Quality Standards for the St. Louis Code are also included to show the maximum dustfall allowable in a given time regardless of the other regulations. The suspended particulate level is also shown.

Other particulate emission codes which are known to be based on the San Francisco Bay Area Code include Gary and Hammond, Indiana, and East Chicago.

The State of Illinois Air Pollution Control Board Regulation for cement kilns states that[18]: "All new cement kilns shall be equipped with gas cleaning devices to reduce the particulate matter in the gas discharged

*See Volume VI.

to the atmosphere to 99.7% of the particulate matter entering the gas cleaning device. However, particulate matter discharged to the atmosphere shall not exceed 0.1 grain per standard cubic foot regardless of the degree of efficiency required by the gas cleaning device." Although the 0.1 grain/SCF is not as restrictive as other codes the requirement for 99.7% collection efficiency is quite stringent.

In regards to air pollution control regulations for cement plants on a worldwide basis, the literature indicates that the Los Angeles County Code is the most stringent regulation in the world today. This is also in agreement with the opinions of the cement plant officials that were consulted during this study.

SECTION 7

DRAFT REGULATION

In 7.1, a notification is presented as required by the draft of the National Air Quality Standards Act of 1970 preliminary to the publication of proposed regulations establishing Federal Standards of Performance for specific industries. A proposed regulation for the steam-electric power generation industry is given in 7.2 and a brief discussion of the rational of this regulation is given in 7.3. This approach to the establishment of Federal Standards of Performance is based upon plant capacity and production rate only and allows the operator a number of options.

In 7.4 an optional regulation is given based on pollutant concentrations in the emitted gas stream. Testing procedures are specified in Section 7.5 which are adaptable to either form of regulation. These were written for the optional regulation given in 7.4.

7.1 Notification

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Office of the Secretary

CONTROL OF AIR POLLUTION FROM
MAJOR STATIONARY SOURCES

Pursuant to provisions of Section 113 of the National Air Quality Standard Act of 1970, notice is given that the following categories of new stationary sources of emission will be subject to Federal Standards of Performance:

(1) steam-electric generating units

(2) municipal incinerators

(3) Portland cement plants

(4) nitric acid plants

(5) sulfuric acid plants

The Secretary shall within one hundred and twenty (120) days after publication of this notice, publish proposed regulations, in accordance with Section 553 of title 5 of the United States Code, establishing Federal Standards of Performance for the listed new sources of emissions. Such standards will be based on the greatest degree of emission control which is achievable through application of the available control technology, processes, operating methods, or other alternatives. Interested persons will be given an opportunity for written comment on such proposed regulations.

The Secretary shall review appropriate written comments and will promulgate the Federal Standards of Performance with such modifications as may be deemed appropriate within ninety days after publication of

the proposed regulations establishing Federal Standards of Performance. The effective date is the date of promulgation. The various states will be notified of such promulgation.

Dated: _____

_____

Elliot T. Richardson
Secretary

7.2 Draft Regulation

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Office of the Secretary

FEDERAL STANDARDS OF PERFORMANCE FOR AIR POLLUTION
BY NEW STEAM-ELECTRIC GENERATING PLANTS

Pursuant to provisions of Section 113 of the National Air Quality Standard Act of 1970 and to the notice published in the Federal register on November 15, 1970 there are published herein the Federal Standards of Performance established for steam-electric generating plants.

1.0 REGULATION NO. 1

For new steam-electric generating plants, no person shall cause or allow to be emitted into the atmosphere from any fuel burning equipment particulate material in excess of the following amounts:

(a) For facilities with rated hourly capacities that equal or are less than 100 million BTU gross heat input the particulate emissions shall not exceed 0.4 lbs. per million BTU gross heat input to the facility.

(b) For facilities with rated hourly capacities in excess of 100 million BTU but not exceeding 10,000 million BTU gross heat input, particulate emissions shall not exceed 0.2 lbs. per million BTU gross heat input to the facility.

(c) For facilities with rated hourly capacities that equal or are less than 10,000 million BTU gross heat input, particulate emissions shall not exceed 0.1 lbs. per million BTU gross heat input to the facility.

2.0 REGULATION NO. 2

For new steam-electric generating plants, no person shall cause or allow to be emitted into the atmosphere from any fuel burning equipment sulfur dioxide in excess of 0.3 lbs. per million BTU gross heat input to the facility.

3.0 REGULATION NO. 3

For new steam-electric generating plants, no person shall cause or allow to be emitted into the atmosphere from any fuel burning equipment oxides of nitrogen in excess of 0.5 lbs. per million BTU gross heat input to the facility.

4.0 REGULATION NO. 4

No person shall cause or allow the emission of a gas plume from the fuel burning apparatus of a steam-electric generating facility where the gas plume is:

(a) Of a shade or density as dark or darker than that designated as (No. 1) on the Ringelmann Chart, except that for periods aggregating not more than five (5) minutes in any one (1) hour of an eight (8) hour period a gas plume of a shade or density as dark as that designated as (No. 1) but not darker than that designated as (No. 2) on said Ringelmann Chart, is permitted.

(b) Of such opacity as to obscure an observer's view to a degree equal to a gas plume of the shade or density described in above.

Where the presence of uncombined water causes an emission to exceed the limits set forth in above, said limits shall not apply.

7.3 Discussion of Draft Regulation

In deriving the Federal Standards of Performance as given in the proposed regulations, an attempt was made to make the proposed standard as simple as possible while accomplishing the purpose of establishing stringent emission control. Because the purpose of steam-electric generating facilities is to convert energy from one form to another, the proposed standards are in terms of allowed emissions per unit of energy utilized in the process, thus applying equally to gas, oil, or coal. The advantage of this approach is that the power companies are given discretion in choosing the fuel, in designing emission control systems, and in other process variables. Alternative standards could have been based upon allowed volume percentages of emissions per volume of gas flow in the discharge stream or upon performance of emission control devices. These alternatives were not selected because they do not put a direct limit on the pollution load on the atmosphere in terms of energy production.

With respect to the particulate emission rate established, it may be noted that gas fired generators will be able to meet these standards without emission control devices but that a typical coal burning plant will require a particulate collector with efficiency in excess of 90 percent. For good quality fuel oil the required emission levels can also be obtained without control. In addition, it may be desirable to require in every case the provision of a particulate collector with efficiency in excess of 90 percent regardless of the fuel being used. This is not

suggested here in order to keep the Federal Standard uniform in terms of pollution load on the atmosphere. It could be expected that standards established by many states would include the above requirement.

With respect to sulfur dioxide emission it is to be noted that the required emission level can be obtained with utilization of coal containing no more than 0.2% sulfur. Since coal of this quality is difficult to obtain, one would expect that it would be more common to use coal containing 1 percent sulfur along with an 80 percent efficient sulfur dioxide scrubber or to desulfurize the coal. The proposed standard allows this type of flexibility.

The standard for sulfur dioxide can also be readily met with natural gas but not so readily with fuel oil. One percent fuel oil would require a desulfurization of exhaust gases.

The proposed standard with respect to oxides of nitrogen is less soundly based than the other proposed standards because emission levels depend to a considerable extent upon the combustion process and not so much upon the nitrogen content of the fuel. However, based upon limited data on nitrogen oxides produced in gas, coal, and oil steam-electric generators, it appears that the suggested level is within technological capabilities but will require varying degrees of process control to be realized.

The proposed standard for visibles is common and based upon the Ringelmann Chart rather than the spot-test because of relative ease of

instrumentation and common knowledge of the former. It would be possible to substitute a spot-test for this standard upon provision of more suitable data, however, at present the Ringelmann Chart appears most suitable even with its rather gross inaccuracies.

Optional Draft Regulation

PART ___. CONTROL OF AIR POLLUTION FROM STEAM - ELECTRIC GENERATING UNITS

Sec.

SUBPART A - GENERAL REQUIREMENTS

00.1 Definitions

00.2 Abbreviations

SUBPART B - ALLOWABLE EMISSIONS

00.3 Particulate Matter

00.4 Sulfur Oxides

00.5 Nitrogen Oxides

00.6 Visible Emissions

SUBPART C - TESTING PROCEDURES

00.7 Introduction

00.8 Sampling for Particulate Matter

00.9 Sampling for Sulfur Oxides

00.10 Sampling for Nitrogen Oxides

00.11 Sampling for Carbon Dioxide

00.12 Standardization of Gases and Reporting of Results of Source Tests

SUBPART D - INFORMATION REPORTING

00.13 Source Tests

Subpart A - General Provisions

§00.1 Definitions

(a) As used in this part, all terms not defined herein shall have the meaning given them in the Act:

(1) "Act" means the National Air Quality Standards Act of 1970, _____ U.S.C. _____ et seq.

(2) "Secretary" means the Secretary of Health, Education, and Welfare and any other officer or employee of the Department of Health, Education, and Welfare or any officer or employee of an Air Quality Control Region or any person to whom the authority involved may be delegated.

(3) Atmosphere - Atmosphere is the air that envelopes or surrounds the earth.

(4) Breeching - Breeching is the duct for conveying the gases from the heat exchanger system to the inlet of the collection system and from the outlet of the collection system to the chimney.

(5) Collection System - Collection system is any equipment used singly or in combinations which removes, reduces, or renders less noxious air contaminants present in the gases from fuel-burning equipment at a point where such gases enter the collection system.

(6) Control Equipment - Control equipment is any equipment which is used for the primary purpose of regulating the release of contaminants from fuel-burning equipment by reducing the creation of air contaminants or the emission of air contaminants into the atmosphere, or both

(7) Emission - Emission is the act of releasing gases into the atmosphere or the material so passed into the atmosphere.

(8) Fuel - Fuel is any form of combustible matter - solid, liquid, or gas but does not include refuse.

(9) Fuel-Burning Equipment - Fuel-burning equipment is any furnace, boiler, apparatus, stack, and all appurtenances thereto used in the process of burning fuel for the primary purpose of producing heat for the generation of steam for a steam electric generating unit.

(10) Gas Plume - Gas plume is the visible stream of gases discharged into the atmosphere from a stack.

(11) Gases - Gases are any gas or combination of gas and particulate matter which is discharged from fuel-burning equipment.

(12) Heat Exchanger System - Heat exchanger system is the boiler, superheater, economizer, and all other units where heat is transferred from the gases to the water or steam.

(13) Heat Input - Heat input is the gross calorific value of the fuel charged into the boiler furnace.

(14) Opacity - Opacity is the state of a substance which renders it partially or wholly impervious to the rays of light. Opacity as used in this regulation refers to the obstruction of an observer's view.

(15) Particulate Matter - Particulate matter is material other than uncombined water, which is suspended in the gases or discharged into the atmosphere in a finely divided form as a liquid or solid, at standard conditions.

(16) Person - Person means any individual, partnership, partner, firm, company, corporation, association, joint stock company, trust, estate, governmental entity, or any other legal entity, or their legal respresentatives, agents, or assigns.

(17) Ringelmann Chart - Ringelmann Chart is the chart published and described in the United States Bureau of Mines Information Circular 8333, and on which are illustrated graduated shades of grey to black for use in estimating the light obscuring capacity of smoke.

(18) Stack - Stack is a duct, chimney, flue, conduit, vent or opening designed or arranged for the emission of gases into the atmosphere.

(19) Standard Conditions - The term "standard conditions" means a gas temperature of 70 degrees Fahrenheit and a gas pressure of 29.92 in. Hg.

(20) Steam Electric Generating Unit - Steam electric generating unit is any assembly of equipment, apparatus, or structures used in the process of generating electricity from steam produced by heat transferred from the gases produced from the combustion of fuel to water and steam of the system.

§ 00.2 Abbreviations

The abbreviations used in this part have the following meanings in both capital and lower case:

ASTM - American Society for Testing and Materials

BTU - British Thermal Unit

lb. - Pound(s)

SCFM - Standard cubic feet per minute

ppm - Parts per million

N - Normal

SO_2 - Sulfur Dioxide

SO_3 - Sulfur Trioxide

NO_2 - Nitrogen Dioxide

Hg - Mercury

In. - Inches

No. - Number

OD - Outside Diameter

SF - Square Feet

% - Percent

ID - Inside Diameter

mm - Millimeter(s)

ml - Milliliter (s)

$BaCl_2$ - Barium Chloride

H_2O - Water

CO_2 - Carbon Dioxide

°F - Degrees Fahrenheit

Abbreviations (Continued)

<	-	Less Than
>	-	More Than
±	-	Plus or Minus
e.g.	-	For Example
i.e.	-	That Is
°C	-	Degrees Centrigrade
H_2O_2	-	Hydrogen Peroxide
gm	-	Gram(s)
H_2SO_4	-	Sulfuric Acid
KNO_3	-	Potassium Nitrate
mg	-	Milligram(s)
NaOH	-	Sodium Hydroxide
mμ	-	Millimicron(s)

Subpart B - Allowable Emissions

§00.3 Particulate Matter

(a) For new steam electric generating units, no person shall cause or allow to be emitted into the atmosphere from any fuel-burning equipment or to pass a reasonable measuring point in the stack or breeching, particulate matter in the gases in excess of (0.06) lb. per 1,000 lb. of gases, standardized to 12% CO_2 by volume.

(b) For steam electric generating units beginning two years after the date of issuance of a certificate to operate by the Secretary, no person shall cause or allow to be emitted into the atmosphere from any fuel-burning equipment or to pass a reasonable measuring point in the stack or breeching, particulate matter in the gases in excess of (0.09) lb. per 1,000 lb. of gases, standardized to 12% CO_2 by volume.

(c) Notwithstanding section (a) and (b) above, all coal-fired installations shall be equipped with, and shall at all times utilize, a particulate collection system which removes not less than (99.0) percent by weight of the particulate matter in the gases passing a reasonable measuring point in the breeching before the gases enter the collection system.

§ 00.4 Sulfur Oxides

(a) No person shall cause or allow to be emitted into the atmosphere from any fuel-burning equipment or to pass a reasonable measuring point in the stack or breeching, sulfur oxides in the gases in excess of (0.40) lb. (measured as SO_2) per 1,000 lb. of gases, standardized to 12% CO_2 by volume.

(b) Notwithstanding section (a) above, all installations shall be equipped with, and shall at all times utilize a gas cleaning system which removes not less than (90.0) percent by weight of the sulfur oxides (measured as SO_2) in the gases passing any reasonable measuring point in the breeching before the gases enter the collection system.

§00.5 Nitrogen Oxides

(a) No person shall cause or allow to be emitted into the atmosphere from any fuel-burning equipment or to pass a reasonable measuring point in the stack or breeching, nitrogen oxides in the gases in excess of 0.60 lb. (measured as NO_2) per 1,000 lb. of gases, standardized to 12% NO_2 by volume.

(b) Notwithstanding section (a) above, all installations shall be equipped with, and shall at all times utilize, a gas cleaning system which removes not less than 50 percent by weight of the nitrogen oxides (measured as NO_2) in the gases passing any reasonable point in the breeching before the gases enter the collection system.

§00.6 Visible Emissions

(a) No person shall cause or allow the emission of a gas plume which is:

A) Of a shade or density as dark or darker than that designated as (No. 1) on the Ringelmann Chart, except that for periods aggregating not more than five (5) minutes in any one (1) hour of an eight (8) hour period a gas plume of a shade or density as dark as that designated as (No. 1) but not darker than that designated as (No. 2) on said Ringelmann Chart, is permitted.

B) Of such opacity as to obscure an observer's view to a degree equal to a gas plume of the shade or density described in (a)(1) above.

Where the presence of uncombined water causes an emission to exceed the limits set forth in (a) above, said limits shall not apply.

7.5 Testing Procedures

§00.7 Introduction

The procedures described in this subpart will constitute the test program to determine the conformity of steam electric generating units with the applicable standards set forth in this part. In all cases, samples shall be taken near the stack outlet, or at a reasonable point in the breeching after the collection system and at a reasonable point in the breeching ahead of the collection system.

In all cases, stack emissions shall be reported in terms of lb. of substance for which the test is being made, per 1,000 lb. of gases, standardized to 12% CO_2 by volume.

§ 00.8 Sampling for Particulate Matter

(a) The following apparatus and reagents are required for obtaining and analyzing the stack sample:

Apparatus (Figure 1)

The sampling apparatus shall consist of a probe, cyclone, filter, four impingers, dry gas meter, vacuum pump, and flow meter as shown in Figure 1. The stainless steel, buttonhook-type probe tip (1) shall be equipped with a 5/8-inch-diameter fitting so that it will form a gas-tight connection (2) to the probe. The probe (3) shall consist of 5/8-inch-outside-diameter medium-wall Pyrex glass tube with a ground-glass joint on one end. The glass probe should be logarithmically wound from the entrance end with 25 feet of 26-guage nickel-chromium wire. During sampling, the wire shall be connected to a calibrated variable transformer to maintain a gas temperature of 250°F in the probe. The wire-wound glass tube shall be wrapped with fiber glass tape and encased in a 1-inch-OD stainless steel tube for protection. The end of the steel tube that does not have the balljoint protuding has a nut welded to it for connection to the stainless steel coupling used to attach the nozzle. The probe connects to a cyclone and flask (4) if used in the train. The cyclone connects to a filter holder (5), which holds a 2-1/2-inch tared glass fiber filter. MSA type 1106 BH filter paper shall be used. The cyclone, flask, and filter shall be contained in an electrically heated enclosed box (6), which is thermostatically

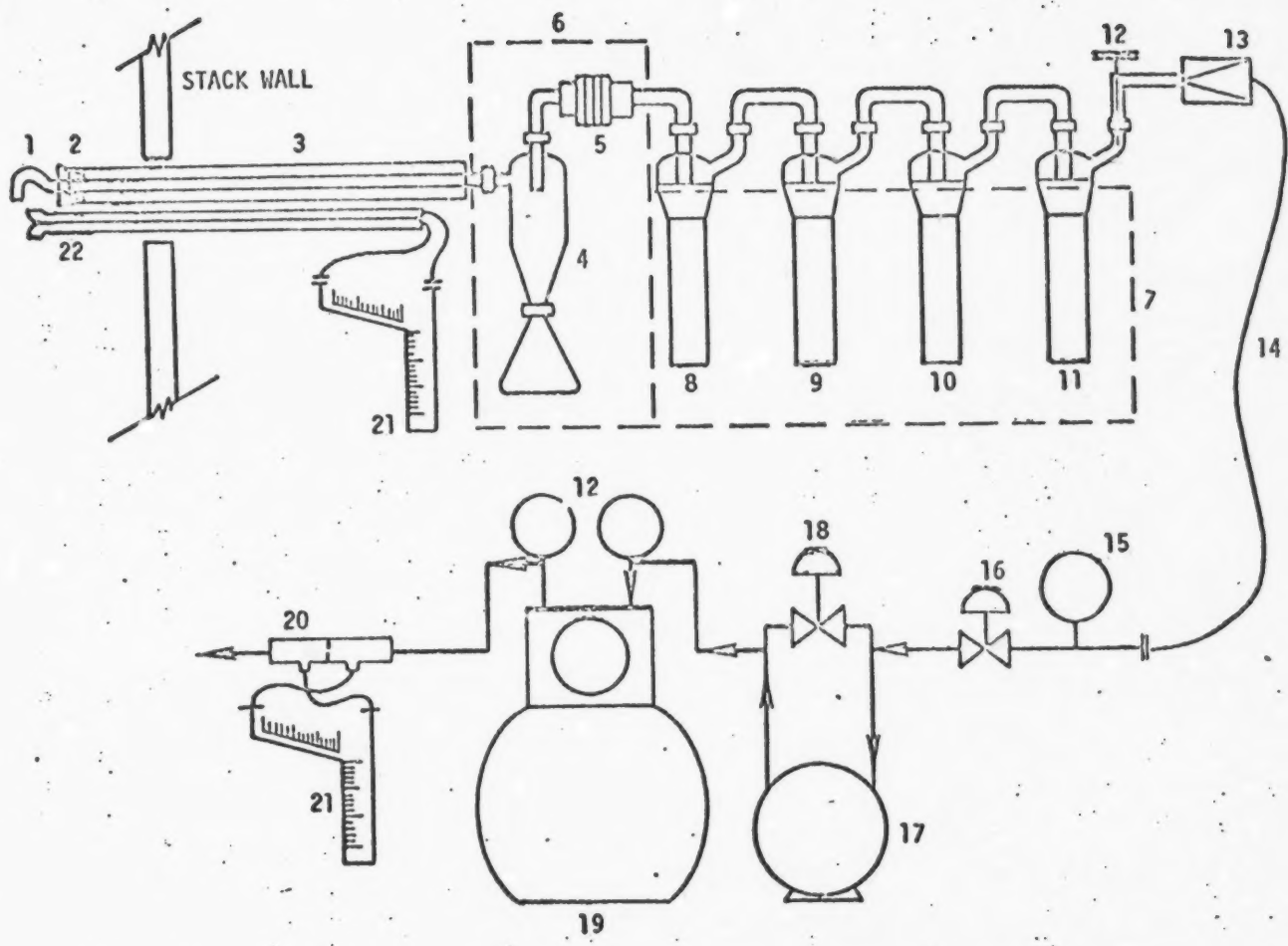

Figure 1. Particulate Sampling Train

maintained at a minimum temperature of 250°F to prevent water condensation. Attached to the heated box shall be an ice bath (7) containing four impingers connected in series with glass balljoints. The first impinger (8) shall receive the gas stream from the filter. This impinger shall be of the Greenburg-Smith design modified by replacing the tip with a 1/2-inch-ID glass tube extending to 0.5 inch from the bottom of the flask. This impinger shall be initially filled with 100 milliliters of distilled water. The second impinger (9) shall be a Greenburg-Smith impinger with tip, and also filled with 100 milliliters of distilled water. The third impinger (10), which is left dry, shall be a Greenburg-Smith impinger modified like the first. The fourth impinger (11) shall also be a Greenburg-Smith type modified like the first and contain approximately 175 grams of accurately weighed dry silica gel.

From the fourth impinger (11) the effluent stream flows through a check valve (13); flexible rubber vacuum tubing (14); vacuum gauge (15); a needle valve (16); a leakless vacuum pump (17) rated at 4 cubic feet per minute at 0 inches of mercury gauge pressure and 0 cubic feet per minute at 26 inches of mercury gauge pressure, and connected in parallel with a by-pass valve (18); and a dry gas meter rated at 1 cubic foot per revolution (19). A calibrated orifice (20) shall complete the train and shall be used to measure instantaneous flow rates.

The three thermometers (12) shall be dial type with a range of 25° to 125°F. A fourth thermometer in the heated portion of the box shall have a range up to 500°F. The dual manometer (21) across the calibrated orifice shall be an inclined-vertical type graduated in hundreths of an inch of water from 0 to 1.0 inch and in tenths from 1 to 10 inches.

Reagents

Water - Distilled water that has been deionized.

Acetone - (Reagent Grade)

Chloroform - (Reagent Grade)

Ether - (Reagent Grade)

(b) The sampling location should be at least eight stack diameters downstream from any bend, expansion, or contraction in the stack or flue, and at least two diameters upstream from any bend and obstruction.

If the tester finds eight diameters impractical, the following rule shall be employed. For a straight flue run of six to eight stack diameters in length, double the number of sampling points. For a length of four to six stack diameters, triple the number of points.

All exhaust gases will be sampled isokinetically at each traverse point as described in (c) below for equal time increments.

(c) Each test shall consist of three samples obtained from three runs with a minimum of ten (10) minutes sampling time per run at each traverse point.

The cross-sectional area of the stack or breeching at the test station shall be divided into a number of concentric equal-area zones for circular stacks, or rectangular equal areas for rectangular stacks or breechings.

The number of areas used shall be in accordance with Table 1.

Cross Sectional Area of Stack or Breeching (SF)	No. of Equal-Area Zones for Stack or Breeching		No. of Traverse Points for Stack or Breeching	
	Circular	Rectangular	Circular	Rectangul
200	8	32	32	32
300	9	36	36	36
400	10	38	40	38
500	11	42	44	42
600	11	44	44	44
700	12	48	48	48
800	13	50	52	50
900	14	54	56	54
1000	14	58	56	58
1100	15	60	60	60
1200	16	64	64	64
1300	17	66	68	66
1400	18	70	72	70

Table 1. Determination of Traverse Points in Stack or Breeching.

Where cross-sectional area is between values listed in table, go to next higher value.

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or breechings,

For rectangular stacks/ each area shall have one traverse point located at the centroid / of the area. Circular stacks shall have four traverse points per area; arranged per Figure 2. The location of each point along a stack diameter is calculated from the expression:

$$P = 50 \left[1 - \sqrt{\frac{(2j - 1)}{2a}}\right] \qquad \text{Equation (1)}$$

Where:

P = Percent of stack diameter from the inside wall to traverse point.

a = Total number of areas being used.

j = Number of the area for which the location is being calculated, number 1,2,3, ... from the center outward.

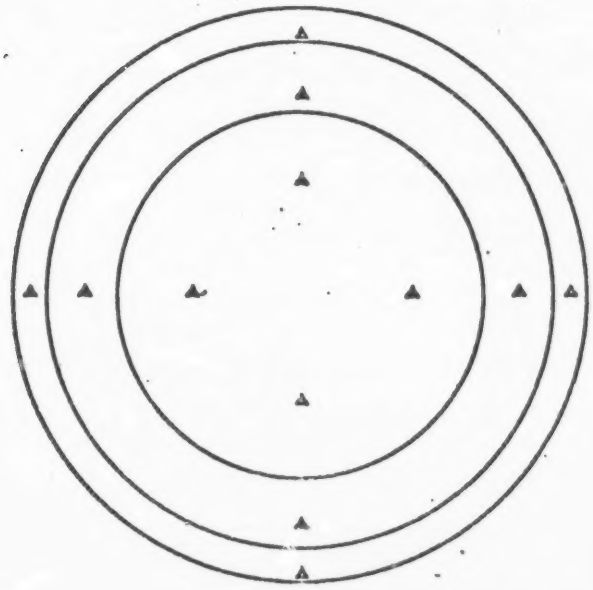

Figure 2. Cross section of a circular stack divided into three concentric equal areas, showing location of traverse point. The location of such points for a stack of given diameter can be determined by referring to Equation (1).

Equation (1) gives half of the values needed, with the remaining half being the differences of each percentage from 100. All particulate sampling shall be conducted with $\pm^{10}_{\wedge}$ percent of isokinetic conditions.

Measurements of stack gas flow by Pitot tube to determine isokinetic sampling rates shall have the following precision in the ranges indicated:

Range	Sensitivity
< 0.10 inch of water	0.001 inch of water
> 0.10 inch of water	0.01 inch of water

Sampling rate shall be adjusted to maintain isokinetic sampling conditions; i.e., the velocity in the tip of the sample probe nozzle should equal the velocity in the stack at the sample point. The sampling rate shall be at least 0.5 standard cubic foot per minute.

In order to maintain isokinetic sampling at all times, the following procedure, or equivalent, shall be followed:

1) A calibrated Pitot tube or similar device for measuring velocity pressure and a thermocouple or a similar device for measuring stack temperature ($\pm$ 5°F) shall be attached to the sample-collection probe to measure velocity pressure and stack temperature at the sample point.

2) A family of curves for different stack temperatures may be prepared for each boiler tested so that isokinetic sampling can be maintained by reading and adjusting the gas flow rate through the sample train orifice or a similar device, which has a maximum absolute error of less than 5 percent of the sampling rate. (Note: On an arithmetic graph the family of curves will be straight lines; therefore, only one point need be calculated to determine the location of each curve).

In order to insure acceptable operation of the fuel-burning/equipment and testing equipment, the tester shall keep records at 5-minute intervals of physical parameters that influence the performance, e.g., pressure difference across the orifice and stack gas temperature.

(d) After all traverse points have been sampled one time, the collection train shall be removed from the test site by placing the various components into plastic containers and treated as follows:

Container No. 1 - Carefully remove the filter from the filter holder and place in the container and seal with tape.

Container No. 2 - Shall contain any loose particulate and acetone washings for the probe, cyclone, cyclone flask, and front half of the filter holder. The inside of the cyclone, cyclone flask, and front half of the

filter holder shall be wiped with a rubber policeman, and the inside of the probe with a soft rubber plunger fitted on a stainless steel rod, to loosen adhering organics and carbon. The loosened particle shall then be washed into the container with acetone, and the container shall be sealed with tape.

Container No. 3 - The H_2O from the first three Greenburg-Smith impingers shall be measured within ±2 milliliters and placed in the container. H_2O rinsings from the back half of the filter holder, the fritted glass support, all connectors, and the first three Greenburg-Smith impingers shall also be placed in this container and the container sealed with tape.

Container No. 4 - Silica gel from the fourth Greenburg-Smith impinger shall be returned to the original container and sealed with tape. A rubber policeman may be used as an aid in removing the silica gel from the impinger, but no liquid may be used.

Container No. 5 - The back half of the filter holder, fritted support, all connectors, and the first three Greenburg-Smith impingers shall be thoroughly rinsed with acetone, and the washings placed in this container and sealed with tape.

(e) The sample shall be analyzed as follows:

Container No. 1 - Transfer the filter and any loose particulate from the sample container to a tared glass weighing dish and desicate for 24 hours in a desicator or constant humidity chamber containing a saturated solution of calcium chloride or its equivalent. Weigh to a constant weight and report the results to the nearest 0.1 milligram.

Container No. 2 - Transfer the acetone washings from the probe, cyclone, cyclone flask, and front half of the filter holder to a tared beaker, and evaporate to dryness at ambient temperature and pressure. Desicate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 milligram.

Container No. 3 - Extract organic particulate from the impinger solution with three 25-milliliter portions of chloroform and three 25-milliliter portions of ethyl ether. Combine the ether and chloroform extracts, and transfer to a tared beaker. Evaporate until no solvent remains at about 70°F. This may be accomplished by blowing air filtered through activated charcoal over the sample. Desicate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 milligram.

Container No. 4 - Determine the amount of moisture absorbed by weighing the spent silica gel to the nearest 0.1 gram and making appropriate calculations. The amount of water so found is to be added to that condensed in the impingers.

Container No. 5 - Transfer the acetone washings from the back half of the filter holder, fritted support, connectors, and first three Greenburg-Smith impingers to a tared beaker, and evaporate to dryness at ambient temperature and pressure. Desicate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 milligram.

The total particulate weight shall be obtained by totaling the weights of the individual sample components. Emissions shall be calculated in terms of lb. per hour by dividing the sample weight in pounds by the sampling time in hours.

§ 00.9 Sampling for Sulfur Oxides

(a) The following apparatus and reagents are required for obtaining and analyzing the stack sample:

Apparatus

Sampling Probe - Glass tubing (preferably borosilicate or quartz) of suitable size with a ball joint at one end and a removable filter at the other

It may be necessary to support the glass probe in a stainless steel pipe; if the stack gas temperature exceeds 500°C, a water-cooled jacket of metal may be required.

Filter - A filter is needed to remove particulate matter, which may contain metal sulfates and cause interference during analysis. Borosilicate glass wool, Kaolin wool, or silica wool are suitable filters for removing particulate matter. ~~(Ammonia or certain~~

Adapter - Six plug-type connecting tubes T 24/40, one with a 90° bend and a socket joint.

Heating Tape - An insulated heating tape with a powerstat to prevent condensation in exposed portion of probe and adapter. Alternative: glass wool or other suitable insulators.

Dry Gas Meter - A 0.1 cubic-foot-per-revolution dry gas meter equipped with a fitting for a thermometer and a manometer. Alternatively, a calibrated tank or a rotameter calibrated at the operating pressure may be used.

Vacuum Pump

Thermometers - One 10-50°C, ± 1°C, and one 0-300°C ±5°C are suitable.

Manometer - A 36-inch-Hg manometer.

Absorbers - Two U shaped ASTM D 1266 lamp sulfur absorbers with coarse-sintered plates.

Filter Tube - One 40-mm-diameter Corning medium-sintered plate.

Scrubber fo. Purifying Air - An ASTM D 1266 lamp sulfur absorber with coarse-sintered plate.

Teflon Tubing - Teflon tubing, 1/4-inch-ID, for connecting absorbers. Alternative: 8-mm pyrex tubing with butt-to-butt connections held together with Tygon.

Reagents

Water - Distilled water that has been deionized

Isopropanol, Anhydrous

80 Percent Isopropyl Alcohol - Dilute isopropanol with water at a ratio of 4 to 1.

30 Percent Hydrogen Peroxide - (Reagent Grade)

3 Percent Hydrogen Peroxide - Dilute 30 percent hydrogen peroxide with water at a ratio of 10 to 1. Prepare fresh daily.

Barium Chloride - ($BaCl_2 \cdot 2 H_2O$, reagent grade).

0.0100N Alcoholic Barium Chloride - Dissolve 1.2216 grams $BaCl_2 \cdot 2 H_2O$ in 200 ml of water and dilute to 1 liter with isopropanol. Standardize this solution with 0.01 N alcoholic sulfuric acid solution.

Thorin Indicator - 1-(0-arsonophenylazo)-2 naphthol-3, 6-disulfonic acid, disodium salt.

0.2 Percent Thorin Indicator - Dissolve 0.2 gram thorin indicator in 100 ml water. Store in polyethylene bottle.

(b) Set up the apparatus as shown in Figure 3. Place 30 ml of 80 percent isopropyl alcohol in the first absorber and 10 ml in the filter tube. Then add 50 ml of 3 percent hydrogen peroxide to the second absorber. A light film of silicone grease on the upper part of the joints may be used to prevent leakage. Wind the heating tape in a uniform single layer around the exposed portion of the probe and adapter and cover the heating tape with asbestos tape wound in the opposite direction. Place a thermometer between the heating tape and asbestos as near the adapter joint as possible. Connect the heating tape to a powerstat, switch on the current, and maintain the probe and adapter at a temperature at which no condensation will occur (about 250°C). Sample at 0.075 cubic foot per minute until 2 cubic feet or a suitable volume of gas has been sampled. Record the meter readings, temperatures, and

pressures at 10-minute intervals. Note the barometric pressure. Do not sample at a vacuum of more than 8 inches Hg.

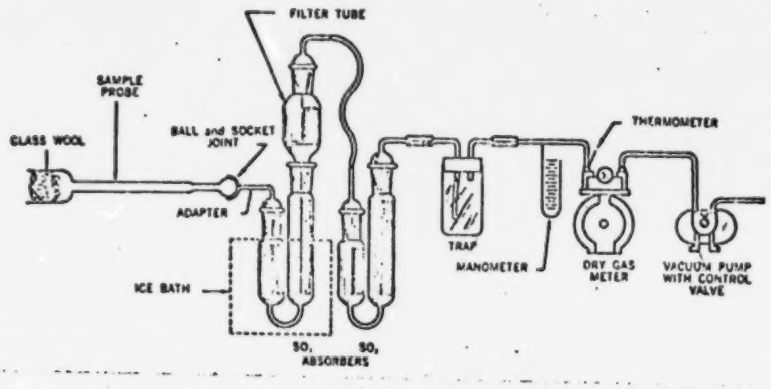

Figure 3. Sulfur Dioxide - Sulfur Trioxide Sampling Train.

(c) After the sample has been obtained, disconnect the asbestos tape, heating tape, probe, and adapter and allow them to cool. Connect the scrubber for purifying air to the inlet of the isopropyl alcohol absorber and add 50 ml of 3 percent hydrogen peroxide. Replace the water in the ice bath with tap water. Draw air through the system for 15 minutes to transfer residual sulfur dioxide to the hydrogen peroxide absorber. Disconnect the purifying air scrubber.

Remove the filter and wash the probe and adapter with 80 percent isopropyl alcohol.

Place the washings in the isopropyl alcohol absorber.

Disconnect the hydrogen peroxide absorber and transfer the contents and the water washings to a 250-ml volumetric flask. Dilute with water to the mark. Analyze for sulfur dioxide.

Stopper the isopropyl alcohol absorber and apply suction to the filter end. Remove the suction line and allow the partial vacuum in the abosrber to draw the solution from the filter. Rinse the filter tube with 80 percent isopropyl alcohol before the suction is lost. Transfer the contents of the isopropyl alcohol absorber and its washings to a 250-ml volumetric flask and dilute to the mark with 80 percent isopropyl alcohol. Analyze for sulfur tricxide.

(d) Analytical procedures and calculations shall be as follows:

Analytical Procedure

Sulfur Trioxide - Pipet a suitable aliquot to a flask and dilute to 100 ml with 80 percent isopropyl alcohol. Add a few drops of thorin indicator (enough to give a yellow color). Titrate with 0.01N $BaCl_2$ to the pink end point. Run a blank determination in parallel.

Sulfur Dioxide - Transfer a suitable aliquot to a flask and add 4 times this volume of isopropyl alcohol. Dilute 100 ml with 80 percent isopropyl alcohol, add enough thorin indicator to give a yellow color, and titrate with standard 0.01N $BaCl_2$ to the pink end point. Run a blank determination in parallel.

Calculations

$$\text{ppm } SO_2 \text{ or } SO_3 \text{ by volume} = \frac{24\ (A-B)\ (N)\ (F)\ (T)}{(V_o)\ (P)}$$

Where

A = ml 0.01N $BaCl_2$ used for titration of sample

B = ml 0.01N $BaCl_2$ used for titration of blank

N = Exact normality of $BaCl_2$

F = Dilution factor

T = Average meter temperature, °R

V_o = Observed volume of gas sample, cu ft

P = Average absolute meter pressure, in. Hg.

$$\text{lb. per hour } SO_2 \text{ or } SO_3 = \frac{60}{387}\ (Q)\ (M)\ (ppm)$$

Where

Q = Volume of flue gas, SCFM

M = Molar weight of SO_2 or SO_3, 64 and 80 lb. respectively

ppm = ppm of SO_2 or SO_3 by volume

§ 00.10 Sampling for Nitrogen Oxides

(a) The following apparatus and reagents are required for obtaining and analyzing the stack sample:

Apparatus (Figure 4.)

Sampling Probe - Stainless steel (type 304 or 316) or glass tubing of suitable size

Collection Flask - A 2-liter round-bottom flask with an outer 24/40 joint for integrated samples or a 250-ml MSA sampling tube for grab samples.

Orifice Assembly - The size of the glass capillary tubing depends on the desired sampling period

Adapter with Stopcock - Adapter for connecting collection flask to sampling T.

Three-way Stopcock.

Manometer - A 36-inch Hg manometer.

Spectrophotometer - Beckman Model B.

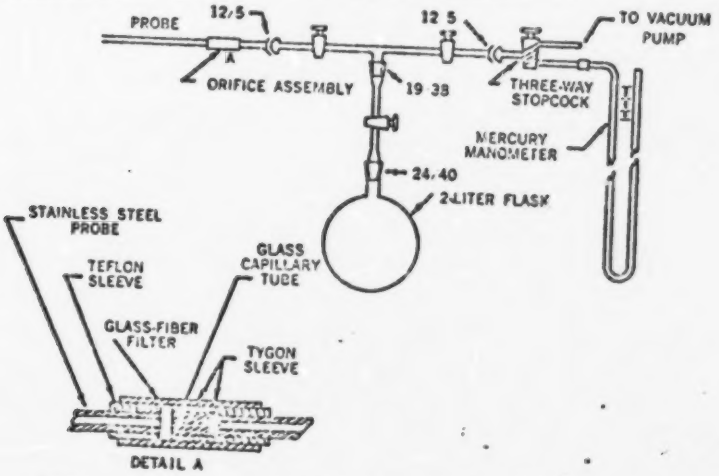

Figure 4. Apparatus for Integrated Grab Samples

Reagents

30 Percent Hydrogen Peroxide - (reagent grade).

3 Percent Hydrogen Peroxide - Dilute 30 percent H_2O_2 with water at 1:1 ratio. Prepare fresh daily.

Concentrated Sulfuric Acid.

0.1N (approximate) Sulfuric Acid - Dilute 2.8 ml concentrated H_2SO_4 to 1 liter with water.

Absorbing Solution - Add 12 drops 3 percent H_2O_2 to each 100ml 0.1N H_2SO_4. Make enough for required number of tests.

1N (approximate) Sodium Hydroxide - Dissolve 40gm NaOH pellets in water and dilute to 1 liter.

Concentrated Ammonium Hydroxide.

Fuming Sulfuric Acid - 15 to 18 percent weight free sulfuric anhydride (oleum).

Phenol - (reagent grade).

Phenoldisulfonic Acid Solution - Dissolve 25 grams of pure white phenol in 150 mlconcentrated H_2SO_4 on a steam bath. Cool and add75 ml fuming sulfuric acid. Heat to 100°C for 2 hours. Store in a dark stoppered bottle. This solution should be colorless if prepared with quality reagents.

Potassium Nitrate-(reagent grade).

Standard Potassium Nitrate Solution - Solution A; Dissolve 0.5495 gram KNO_3 and dilute to 1 liter in a volumetric flask. Solution B; Dilute 100 mlof solution A to 1 liter. One ml of Solution A contains the equivalent of 0.250 mg NO_2 and of Solution B, 0.0250 mg NO_2.

(b) Calibration curves are made to cover different ranges of concentrations. Using a microburette for the first two lower ranges and a 50-ml burette for the next two higher ranges, transfer the following into separate 150-ml beakers (or 200-ml casseroles).

1. 0-100 ppm: 0.0 (blank), 2.0, 4.0, 6.0, 8.0, 10.0, 12.0, 16.0, 20.0 ml of KNO_3 Solution B.
2. 50 - 500 ppm: 0.0 (blank), 1.0, 1.5, 2.0, 3.0, 4.0, 6.0, 8.0, 10.0 ml of KNO_3 Solution A.
3. 500 - 1500 ppm: 0.0 (blank), 5.0, 10.0, 15.0, 20.0, 25.0, 30.0 ml of KNO_3 Solution A.
4. 1500 - 3000 ppm: 0.0 (blank), 15.0, 30.0, 35.0, 40.0, 45.0, 50.0, 55.0, 60.0 ml KNO_3 Solution A.

Add 25.0 ml absorbing solution to each beaker. Follow as directed in (e) below starting with the addition of 1N NaOH.

After the yellow color has developed, make dilutions for the following ranges as follows: 50-500 ppm (1:10), 500 - 1500 ppm (1:20) and 1500 - 3000 ppm (1:50). Read the absorbency of each solution at 420 mμ.

Plot concentrations against absorbencies on rectangular graph paper. A new calibration curve shall be made with each new batch of phenoldisulfonic acid solution.

(c) Sampling shall be done by one of the following procedures:

1) Integrated Grab Sample - Add 25 ml freshly prepared absorbing solution into the flask. Record the exact volume of absorbing solution used.

Set up the apparatus as shown in Figure 4 ; attach the selected orifice. Purge the probe and orifice assembly with the gas to be tested before sampling begins by applying suction to it. Evacuate the system to the vapor pressure of the solution; this pressure is reached when the solution begins to boil. Record the pressure in the flask and the ambient temperature. Open the valve to the sampling probe to collect the sample. Constant flow will be maintained until the pressure reaches 0.53 of the atmospheric pressure. Stop before this point is reached. During sampling, check the rate of all of the mercury in one leg of the manometer in case clogging, especially of the orifice, occurs. At the end of the sampling period, record the pressure, temperature and barometric pressure.

(d) After the sample has been obtained, whether an integrated grab or grab sample, shake the flask for fifteen (15) minutes and allow to stand overnight.

(e) Analytical procedures and calculations shall be as follows:

Analytical Procedure

Transfer the contents of the collection flask to a beaker. Wash the flask three times with 15-ml portions of H_2O and add the washings to the solution in the beaker. For a blank add 25 ml absorbing solution and 45 ml H_2O to a beaker. Proceed as follows for the blank and samples.

Add 1N NaOH to the beaker until the solution is just alkaline to litmus paper. Evaporate the solution to dryness on a water bath and allow to cool. Carefully add 2 ml phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a glass rod making sure that all the residue comes into contact with the solution. Add 1 ml H_2O and 4 drops concentrated H_2SO_4. Heat the solution on the water bath for 3 minutes with occasional stirring.

Allow the solution to cool and add 20 ml H_2O, mix well by stirring, and add 10 ml concentrated NH_4OH, dropwise, with constant stirring. Transfer the solution to 50-ml volumetric flask, washing the beaker three times with 4 to 5-ml portions of H_2O. Dilute to mark with water and mix thoroughly. Transfer a portion of the solution to a dry, clean centrifuge tube and centrifuge, or filter a portion of the solution.

Read the absorbency of each sample at 420 mμ. If absorbency is higher than 0.6, make a suitable dilution of the sample and the blank and read the absorbency.

Calculations

$$\text{ppm } NO_2 = \frac{(5.24 \times 10^5)\ (C)}{V_s}$$

where C = concentration of NO_2, mg (from calibration chart)

V_s = gas sample volume at 70°F and 29.92 inches Hg, ml.

$$\text{lb. per hour } NO_2 = \frac{60\ (Q)\ (M)\ (ppm)}{387}$$

where Q = volume of flue gas, SCFM

M = molar weight of NO_2, 23 lb.

ppm = ppm of NO_2 by volume

§00.11 Sampling for Carbon Dioxide

(a) The following apparatus is required for obtaining and analyzing the stack sample:

1. Stainless steel probe
2. 1-mil Mylar bag
3. Polyethylene container
4. Vacuum pump and flow meter
5. Orsat analyzer

(b) The Mylar bag shall be inserted into the polyethylene container or similar leakproof, rigid container. The inlet fitting on the Mylar bag shall then be pulled through a hole in the polyethylene container and sealed so that a vacuum can be drawn on the container. A piece of thick-walled tubing shall be attached to the fitting on the container and connected to a flow meter and vacuum pump. Pull a vacuum in the polyethylene container, thereby drawing a sample into the Mylar bag. The sample obtained shall then be analyzed with an Orsat analyzer.

(c) Any convenient sampling rate may be used as long as the bag does not fill before the end of a test run. As stack velocity changes occur, the sampling rate shall be adjusted in direct proportion to the changes.

Before sampling, the Mylar bag shall be evacuated with the vacuum pump. In addition, a piece of glass wool may be

...e end of the probe to prevent particulate from ...mi... the bag. A flow meter shall be placed between the probe and Mylar bag for detection of leaks in the bag and container.

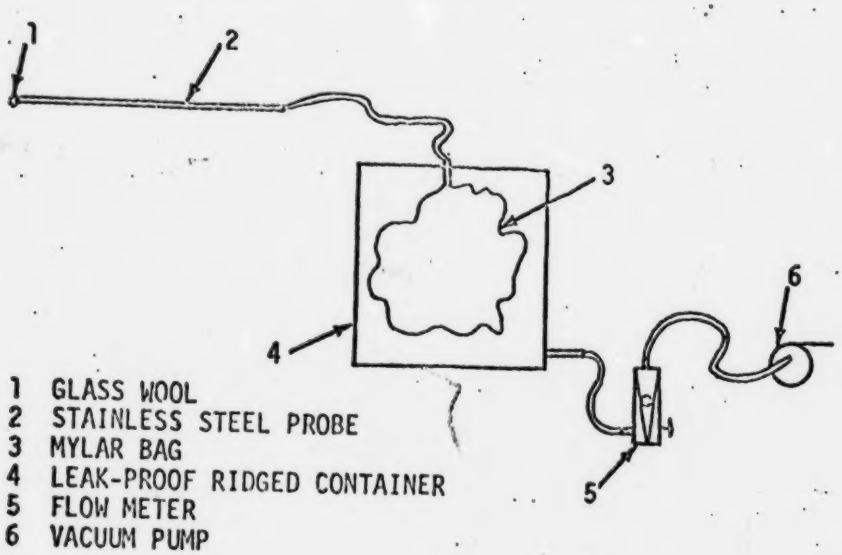

Figure 6. Schematic diagram of carbon dioxide sampling train.

(d) After the sample has been obtained and analyzed with the Orsat analyzer, report the amount of CO_2 found in the gases as percent by volume on a dry basis.

600.12 Standardization of Gases and Reporting of Results of Source Tests

(a) The results of all tests shall be reported in terms of lb. substance tested per 1,000 lb. gases standardized to 12% CO_2 by volume.

(b) Calculations shall be as follows:

$$\frac{\text{lb. Particulate, } SO_2\text{, or } NO_2}{\text{1,000 lb. gases}} = \frac{(Q)(12\%)}{(V)}$$

Where:

Q = Weight of particulate, SO_2, or NO_2 collected, lb.

V = Percent CO_2 in gases, value basis

Subpart D - Information Reporting

§00.13 Source Tests

(a) Each person who owns or operates a steam electric generating unit shall submit biennially to the Secretary, a report of source tests for Particulate, Sulfur Oxides, and Nitrogen Oxides emissions made in accordance with Subpart C above. The due date of each report will be measured from the date of issuance of a certificate of operation by the Secretary made pursuant to the certification procedures outlined in 45 CFR Part _____.

(b) The content and format of the source tests report shall be as required by the Secretary.